# REPAIR DURATION EFFECTS ON DISTRIBUTION SYSTEM RELIABILITY INDICES AND CUSTOMER OUTAGE COSTS

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# ABSTRACT

The distribution system is part of the electric power system that links the bulk transmission system and the individual customers. Approximately 80 percent of outages experienced by the customers are due to failures in the distribution system. It is therefore important to understand the impact of the outages on the customer outage costs and the system reliability.

This thesis evaluates various analytical and simulation techniques which incorporate varying degrees of complexity and data to evaluate the expected customer costs at the system and load level of a radial distribution system. A computer program based on time sequential Monte Carlo simulation has been developed. The results show that certain analytical techniques provide as accurate results as using a Monte Carlo simulation technique.

This research work then analyzes the effect of repair duration distributions on the expected customer costs and the system and reliability indices including annual outage duration at the load points using Monte Carlo simulation technique. Certain repair duration distributions caused expected customer outage costs to increase by 30% for the system and over 50% at certain load points. Some reliability indices were also directly affected by the application of repair duration distribution. This research work thus provides a basic guide to the difference in the expected costs and reliability indices when choosing a particular technique and the type of repair duration distribution.

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## DEDICATION

To those who dared to dream
and make it this far.

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| | |
|---|---|
| ASIFI | Average System Interruption Frequency Index |
| ASIDI | Average System Interruption Duration Index |
| CEMIn | Customers Experiencing Multiple Interruptions |
| CELIDn | Customer Experiencing Longest Interruption Duration |
| CDF | Customer Damage Function |
| CCDF | Composite Customer Damage Function |
| CAIDI | Customer Average Interruption Duration Index |
| CEA | Canadian Electricity Association |
| CIC | Customer Interruption Cost |
| ECOST | Expected Interruption Cost |
| FMEA | Failure Mode and Effect Analysis |
| HLI | Hierarchical Level I |
| HLII | Hierarchical Level II |
| HLIII | Hierarchical Level III |
| IOR | Index of Reliability |
| RBTS | Roy Billinton Test System |
| RT | Repair Time |
| ST | Switching Time |
| SAIFI | System Average Interruption Frequency Index |
| SAIDI | System Average Interruption Duration Index |
| SIC | Standardized Industrial Classification |
| TTF | Times to Failure |
| *Int* | Interruption |
| *Cust* | Customer |
| *Hr* | Hour |
| *f* | Failure |
| *kW* | Kilowatts |

# CHAPTER 1
# INTRODUCTION

## 1.1 Background

An electric power system is required to supply electricity to customers with reasonable continuity and adequacy and as economically as possible. The system reliability can be increased with an increase in investment in the planning and operating phases by improving the existing system and development of new infrastructure. However, over-investment can result in non-economic operation of the power system such as higher operating costs which must be reflected in the tariff structure. The finite economic constraint will be infringed even though the system itself may have less failures and hence better supply. The other end is under-investment in the system which will have the opposite effects. It is evident that the continuity and economic constraints can compete. Power system reliability analysis can help determine the balance between economy and continuity and provide the customers with an economical and reliable supply of electricity [1].

The investments related to the reliability of the electric system need to be evaluated in terms of their cost/benefit implications. This form of analysis is referred to as reliability cost/worth analysis and it helps to determine the balance between investment and reliability of the system. There have been many techniques and suitable criteria developed for better power system reliability evaluation over the last few decades [2,3,4,5]. These techniques can be broadly categorized into deterministic and probabilistic methods.

Deterministic techniques for reliability assessment were implemented the earliest and some of them are still prevalent today. However due to the stochastic nature of the system behavior, customer demands and component failures, deterministic techniques cannot incorporate these uncertainties. Probabilistic techniques involve both the severity of an event and the probability of its occurrence for power system reliability evaluation. These techniques have been widely developed and implemented in the areas of design, planning and maintenance with the enhancement of computing resources and availability of suitable reliability data [1]. The procedures and techniques described in this thesis for reliability assessment are probabilistic in nature.

## 1.2 Power System Reliability and Functional Zones

### 1.2.1 Power System Reliability

Power system reliability indicates the overall ability of the power system to provide an adequate supply of electrical energy. It can be divided into the two main aspects of system adequacy and system security as shown in Fig. 1.1 [1].

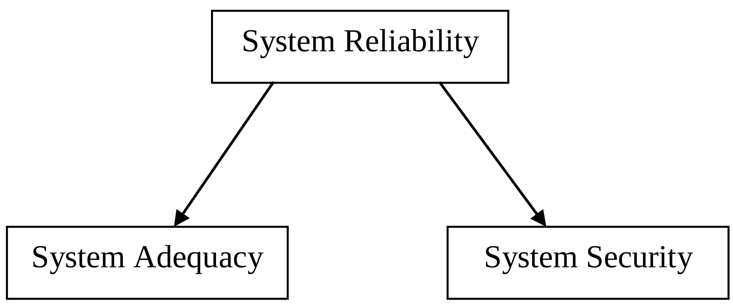


Fig. 1.1 Subdivision of system reliability

Power system adequacy is the ability of the system to supply sufficient energy to its customers. Thus, system adequacy relates to the existence of necessary generation, transmission and distribution facilities within the system to satisfy the customer demand. Adequacy is therefore associated with static conditions and does not include disturbances that occur during the operation of the system. These disturbances, however, are in the system security domain. System security relates to the ability of the system to respond and withstand the disturbances arising within the system without causing widespread cascading events [1]. Most of the probabilistic techniques developed are for system adequacy assessment and this thesis is focussed on this domain.

### 1.2.2 Power System Functional Zones and Hierarchical Levels

A power system can be divided into three functional zones of generation, transmission and distribution for the purposes of planning, operation and analysis. Power system reliability can be conducted in these three basic functional zones or in the combinations that give rise to hierarchical levels [1] as shown in Fig. 1.2

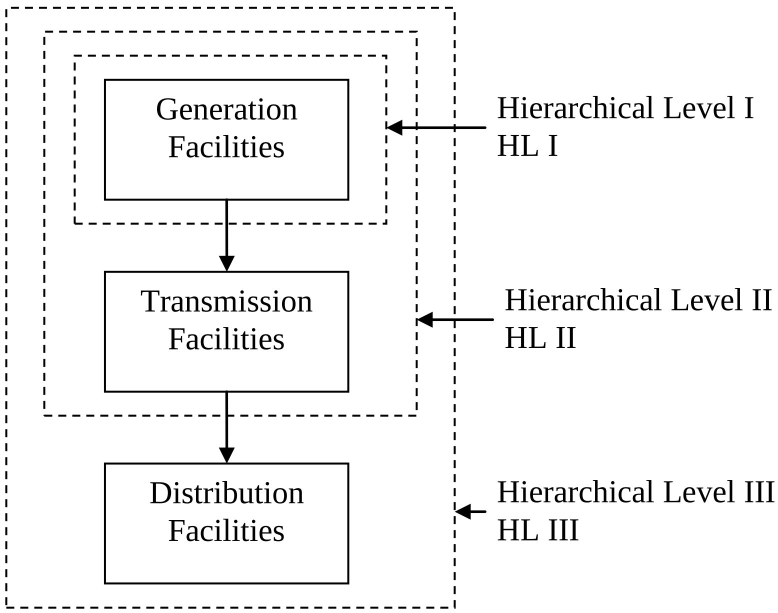


Fig. 1.2 Hierarchical levels in a power system

Reliability assessment at hierarchical level I (HLI) is associated only with the generation facilities required to meet the customer demand. In an HLI study, the system generation is analyzed to determine its ability to meet the total system load requirement considering corrective and protective measures taken of the generating units. Hence, study at this level is also known as "generating capacity reliability evaluation". Transmission and distribution facilities are not included in assessments at this level.

Hierarchical level II (HLII) includes both generation and transmission facilities. Adequacy analysis at this level is also known as "composite system or bulk transmission system evaluation". Reliability assessment at this level is associated with the ability of the generation and transmission systems to deliver energy to the bulk supply points.

Hierarchical level III (HLIII) assessment includes the entire system starting from the generating points and ending at the individual load points. As the actual power systems are very large and complex, analysis at HLIII using a single and direct technique becomes very complicated and difficult. Reliability evaluation of the distribution functional zone is thus performed separately using the HLII load point indices as input values.

### 1.3 Distribution System Reliability

Various probabilistic techniques have been developed and used in distribution system reliability evaluation to obtain quantitative adequacy indices at the individual customer load points. The practical applications of these techniques, however, are not as extensive [1,22]. Distribution system reliability modeling and evaluation has historically received less attention than that of generation or transmission systems. The costs associated with failures in the distribution system are generally relatively low and the effects of the outages in the distribution system are much more localized whereas the failures in the generation system can have widespread economic consequences for the utilities and the society.

Analysis of the customer failure statistics compiled by most utilities clearly point to the failures at the distribution systems resulting in the greatest contribution to the unavailability of supply of power to the customers [1,10]. Thus, a customer connected to a highly reliable generation and transmission system could receive a poor power supply if the distribution system is not very reliable. This demonstrates the need and importance of performing reliability evaluation in the distribution system.

Reliability evaluation of a distribution system is associated with the continuity of supply of energy from the bulk supply points to the individual customer load points. The basic parameters used to evaluate the reliability of a distribution system can be categorized as load point indices and system indices [1]. The load point failure rate, the average outage time and the average annual outage time are the basic load point indices. The system indices can be obtained from these three load point indices and information on the number of customers and load connected at each load point in the system. The set of system reliability indices can be further classified into customer-oriented indices and load-oriented indices [1,3]. Customer-oriented indices include the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), Index of Reliability (IOR), Customers Experiencing Multiple Interruptions (CEMI), and Customers Experiencing Longest Interruption Duration (CELID). Load-oriented indices include Average System Interruption Frequency Index (ASIFI) and Average System Interruption Duration Index (ASIDI).

Due to the stochastic nature of the power system, the annual load point and system indices are functions of component failure rates, repair times and restoration times within that particular year. The average values of these indices can be easily computed as the associated analytical techniques are highly developed for both radial and meshed systems. However, a complete representation of these indices requires knowledge of the underlying probability distributions. This is possible with the use of simulation techniques [9]. The probability distributions of interruption duration have a significant impact on the calculated expected customer outage costs [27]. This thesis will explore the effect on the probability distributions of the reliability indices and variation in the customer outage costs due to application of various repair duration distributions.

## 1.4 Objectives of the Thesis

The first objective of this research work is to compare various analytical and simulation techniques and analyze the results in terms of the expected customer costs at the system and load points for a practical radial distribution system. The analytical techniques vary in their complexity and the data utilized during the evaluation. A computer program was developed based on time sequential Monte Carlo simulation. The simulation approach also incorporates varying degrees of complexity and data to evaluate the expected customer costs at the system and load points. The results thus obtained are compared with those calculated using the analytical techniques.

The second objective of this research work is to analyze the effect of repair duration distributions on the expected outage costs at the system and load points. Instead of the average repair duration of a failed component, various repair duration distributions are applied to examine their effect on the system reliability indices and their probability distributions. The effect of this on the annual outage duration distribution at the load points is also analyzed. The time sequential Monte Carlo simulation technique is used to obtain the respective distributions.

The implication of this research work is to assist the distribution system planner by providing some information on the variation in expected customer costs that can be expected while using analytical and sequential Monte Carlo simulation techniques. This research work will also try to provide some insight to the planner on the variance around the reliability indices and expected costs due to the effect of repair duration distributions.

**1.5 Outline of the Thesis**

This thesis is structured in six chapters. Chapter 1 briefly introduces the background and some general concepts of power system reliability hierarchical levels including the development of distribution system reliability evaluation.

The basic concepts of distribution system reliability evaluation including load point reliability and system reliability indices are presented in Chapter 2. The Roy Billinton Test System (RBTS) is introduced and the distribution network at Bus 6 of the RBTS, which is utilized in this research, is shown in detail. The theory of reliability cost/worth analysis and various standard probability distributions are also introduced in this chapter along with the customer damage functions and calculation of expected customer outage costs.

Chapter 3 describes the basic analytical and Monte Carlo simulation techniques. The failure mode and effect analysis technique for distribution system reliability evaluation is also introduced in this chapter. The algorithm of the computer program developed for this research work is explained and the reliability indices calculated are compared with those obtained using the analytical technique for Bus 6 of the RBTS.

Chapter 4 includes the variation in the expected customer outage costs using analytical and time sequential Monte Carlo simulation techniques. Different analytical and simulation approaches are categorized as case studies. Comparison of the results in the expected costs is done between the cases which grow in complexity in terms of data required and techniques utilized. The conclusion of Chapter 4 summarizes the variation in the results in these various cases.

The effect of the application of the repair duration distributions on the expected customer outage costs at the system and load points are explored in Chapter 5. The variation in the probability distributions of the reliability indices and annual outage duration at load points due to the repair duration distributions in the system are examined in detail in this chapter.

Chapter 6 contains the summary and conclusions of the research described in this thesis.

# CHAPTER 2
# DISTRIBUTION SYSTEM RELIABILITY EVALUATION

## 2.1 Introduction

The development of reliability evaluation has been mainly focused in the areas of generation and transmission in the last few decades. This is primarily due to the capital intensive nature of the generation and transmission systems and that failures in these systems can result in wide-spread catastrophic consequences for both utilities and society [1]. On the other hand, distribution systems are not as capital intensive and the failures in the distribution systems tend to have very localized effects. Therefore, distribution system reliability evaluation has been given relatively less attention.

Canadian customer service continuity statistics compiled by utilities show that approximately 80% of the total customer interruptions are due to the result of failures in the distribution system [13]. A highly reliable generation and transmission system may still result in poor energy supply to the customers if the distribution system is unreliable. Therefore, distribution system reliability evaluation is important to ensure appropriate system reliability levels and to provide effective information for regulatory bodies to set proper benchmarks in the deregulated environment.

Quantitative reliability assessment is an important aspect in distribution system planning and operation. Analysis of past performance and prediction of future performance are two crucial factors of distribution system reliability evaluation. Various analytical and simulation techniques have been developed for reliability assessment of distribution system [1]. A simple distribution system can be represented by a mathematical model and the expected values of the reliability indices can be calculated using analytical techniques. Representing a complex distribution system by a mathematical model may be difficult using an analytical approach and may require approximations to simplify the complex calculations. A simulation approach can be used for reliability evaluation of these distribution systems as it can accommodate the stochastic nature of power system and incorporate its operational constraints [24].

This chapter presents some basic distribution system concepts and the basic load point reliability indices and system reliability indices used for distribution system reliability evaluation. Reliability cost and reliability worth analysis along with the concept of customer damage functions (CDF) used in the analysis are also introduced. Various standard probability distributions are also presented in this chapter. The test system used in this research is taken from the Roy Billinton Test System (RBTS) [19,20] and is also introduced in this chapter.

## 2.2 Distribution System

A distribution system links the bulk electric system to the customers. Distribution systems include sub-transmission lines, distribution substations, primary and secondary feeders, lateral distributors, distribution transformers, protection and sectionalizing equipments and secondary circuits related to supplying power to the customers [26,27]. The objective of quantitative reliability assessment is to determine how adequately all these components perform their intended functions.

A primary feeder or distribution system feeder carries power from the main distribution substation to the secondary substation. The secondary feeder is an extension of the main feeder to reach widely distributed areas. A circuit breaker is usually present in the main feeder. Manual sectionalizing equipment such as disconnects or isolators are also installed at strategic locations on the main feeder for isolating the faulted sections and restoring supply to the healthy sections. The time required to perform isolation and switching actions while a faulted component is being repaired is known as the restoration time [1]. Circuit breakers are assumed to work instantly and without any failures or delay for the purpose of this research work.

Some sections of the distribution system may have the provision for an alternate supply, which is used to supply power to that healthy section of the main feeder when it is disconnected from the main supply after the faulted section has been isolated. The probability associated with the availability of the alternate supply needs to be included in the evaluation if the alternate supply may not always be available. For the purpose of this research work, an alternate supply is assumed to be available whenever needed and can supply all necessary power to the load.

A lateral distributor supplies power to individual customers. Fuses are usually present in the lateral distributors at the junction where they meet the main feeder to isolate the failures in the lateral sections from rest of the main section. The failure of the fuse to work properly will cause the circuit breaker to trip in the main feeder. The probability associated with the successful operation of the fuse can also be included during reliability evaluation. Fuses are assumed to work without failure for the purpose of this research work.

Distribution Systems can be broadly divided into two categories based on their configurations. These are meshed and radial distribution systems.

### 2.2.1 Meshed or Parallel Distribution Systems

Customer load points are supplied by parallel redundant circuits in a meshed distribution system. These circuits form sub-transmission systems that include transmission lines and local substations for delivering electric power from the bulk system to the main load points. This maintains a high reliability level of power supply to the customers. A sub-transmission system is also known as a high voltage distribution system. Many systems may also be constructed as meshed networks but are operated as radial systems using normally open switches. Fig. 2.1 shows the basic structure of a meshed distribution system [25].

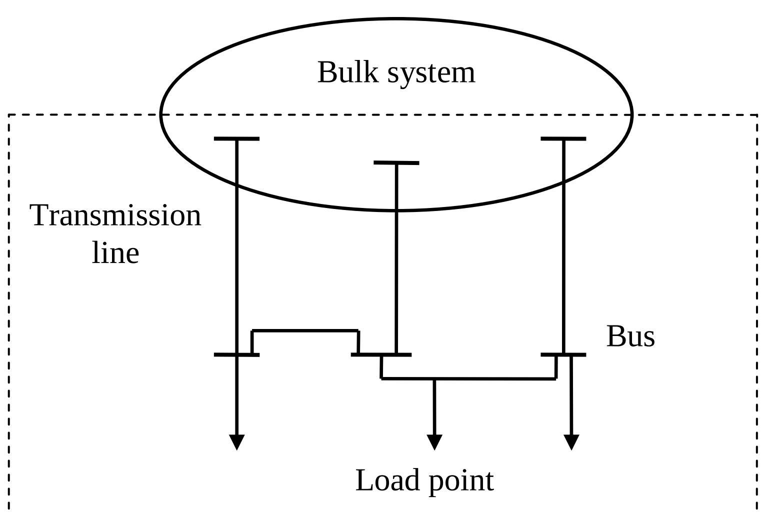


Fig. 2.1 A meshed distribution system

### 2.2.2 Radial Distribution Systems

Most distribution systems are radial in nature because of their low cost and simple design. Most low voltage distribution systems are operated radially. A radial system consists of a series of components between the substation and the load points. Failure of any of these components may result in outage at the load point(s). The duration of the outage depends on the protection and sectionalizing schemes used in the distribution system. The research work presented in this thesis is focused on analyzing a radial distribution system.

Fig 2.2 is an example of a radial distribution system. It receives the main power supply from a transmission or sub-transmission system. It consists of a primary or main feeder and lateral sections or distributors. The main feeder is sectionalized (M1, M2, etc) by disconnects or isolators to isolate faulted sections. Load points LP1, LP2, etc are connected to the main feeder through lateral sections L1, L2, etc. A circuit breaker is usually installed at the beginning of the main feeder from the substation and also at certain lateral sections to protect important equipment or load points. Fuses are usually used in lateral sections to isolate failures on the lateral section from the main feeder. An alternate supply is sometimes provided to restore service in case of failure.

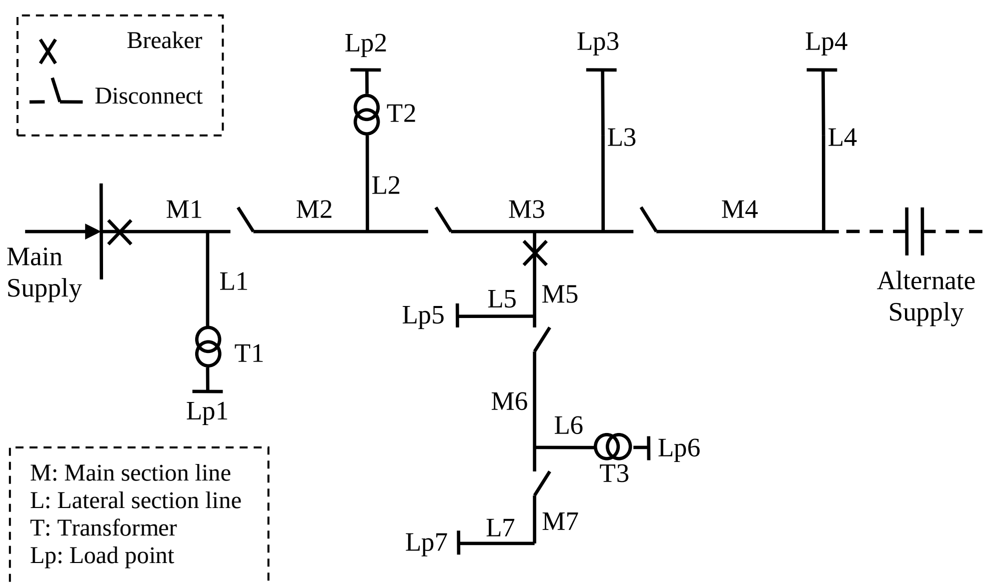


Fig. 2.2 A radial distribution system

### 2.3 Distribution System Reliability Indices

The reliability of a distribution system can be described using two sets of reliability parameters. These are the load point reliability indices and the system reliability indices [1].

#### 2.3.1 Load Point Reliability Indices

A distribution system provides power supply from a substation to individual customer load points. Three basic reliability indices can be used to describe the degree of service continuity. These are the load point average failure rate ($\lambda$), average outage time (r) and the average annual unavailability or average annual outage time (U). The average failure frequency is approximately equal to the average failure rate and indicates the number of failures a load point will experience during a given period of time. The average outage time is the average duration of failure at the load point. The average annual outage time is the average total duration of outage in a year experienced at the load point. It is the product of the average frequency of failure and the average outage time. These reliability indices are expected values and represent the long-run average values.

$$\lambda_i = \sum_j \lambda_j \quad \textit{(f/yr)} \tag{2.1}$$

$$U_i = \sum_j \lambda_j r_j \quad \textit{(hr/yr)} \tag{2.2}$$

$$r_i = \frac{U_i}{\lambda_i} \quad \textit{(hr)} \tag{2.3}$$

Where, $\lambda_j$ and $r_j$ are the failure rate and the average repair time of the component j, and $\lambda_i$, $r_i$ and $U_i$ are the average failure rate, repair time and unavailability at load point i.

#### 2.3.2 System Reliability Indices

Additional reliability indices need to be calculated in order to obtain an overall representation of the system performance. These system reliability indices utilize the basic load point indices and reflect the performance of the system and severity and significance of the system outages. These indices can be used to assess the reliability of a particular feeder, a certain load point, a section of the system or the entire distribution system. The following customer and load-oriented indices were considered [1,5] in this research:

(i) System Average Interruption Duration Index (SAIDI)

This is a measure of the average duration of interruption experienced by the system.

$$SAIDI = \frac{\text{total customer interruption durations}}{\text{total number of customers served}} = \frac{\sum U_i N_i}{\sum N_i} \text{ (hr/cust)} \qquad (2.4)$$

where, $U_i$ is the annual outage time and $N_i$ is the number of customers at load point i.

(ii) System Average Interruption Frequency Index (SAIFI)

This is a measure of the average frequency of interruptions experienced by the system.

$$SAIFI = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}} = \frac{\sum \lambda_i N_i}{\sum N_i} \text{ (int/cust)} \qquad (2.5)$$

where, $\lambda_i$ is the failure rate of load point i.

(iii) Customer Average Interruption Duration Index (CAIDI)

This is a measure of the average duration of interruption experienced by the customer affected by the interruption.

$$CAIDI = \frac{\text{total customer interruption durations}}{\text{total number of customer interruptions}} = \frac{\sum U_i N_i}{\sum \lambda_i N_i} \text{ (hr/int)} \qquad (2.6)$$

(iv) Index of Reliability (IOR)

This is a measure of the average service availability.

$$IOR = \frac{\text{customer hours of service availability}}{\text{customer hours of service demanded}} = \frac{\sum N_i * 8760 - \sum U_i N_i}{\sum N_i * 8760} \qquad (2.7)$$

where, 8760 is the number of hours in a year.

(v) Customers Experiencing Multiple Interruptions ($CEMI_n$)

$CEMI_n$ refers to the percentage of customers interrupted more than n times per year.

$$CEMIn = \frac{\text{number of customers interrupted more than n times}}{\text{total number of customers served}} = \frac{\sum N_{int}}{\sum N_i} \qquad (2.8)$$

where, $N_{int}$ is the number of customers interrupted more than n times at load point i.

(vi) Customers Experiencing Longest Interruption Duration ($CELID_n$)

This index refers to the percentage of customers experiencing longest interruption duration of more than n hour.

$$CELIDn = \frac{\text{number of customers interrupted more than n hours}}{\text{total number of customers served}} = \frac{\sum N_{inh}}{\sum N_i} \qquad (2.9)$$

where, $N_{inh}$ is the number of customers interrupted more than n hours at load point i.

(vii) Average System Interruption Frequency Index (ASIFI)

ASIFI is similar to SAIFI, but instead of number of customers interrupted, the load affected is considered.

$$ASIFI = \frac{\text{load interrupted}}{\text{total load connected}} = \frac{\sum \lambda_i L_i}{\sum L_i} \text{ (int/kW)} \qquad (2.10)$$

where, $L_i$ is the load interrupted at load point i.

(viii) Average System Interruption Duration Index (ASIDI)

ASIDI is a measure of duration of the load interrupted rather than interruption duration experienced by the number of customers.

$$ASIDI = \frac{\text{duration of load interrupted}}{\text{total load connected}} = \frac{\sum U_i L_i}{\sum L_i} \text{ (hr/kW)} \qquad (2.11)$$

where, $L_i$ is the load interrupted at load point i.

### 2.4 Roy Billinton Test System (RBTS)

The RBTS is a test system developed at the University of Saskatchewan. It has a total installed generation capacity of 240 MW supplied by eleven generating units. The annual peak load for the RBTS is 185 MW. This test system has been widely used for reliability assessment of generation, transmission and distribution systems.

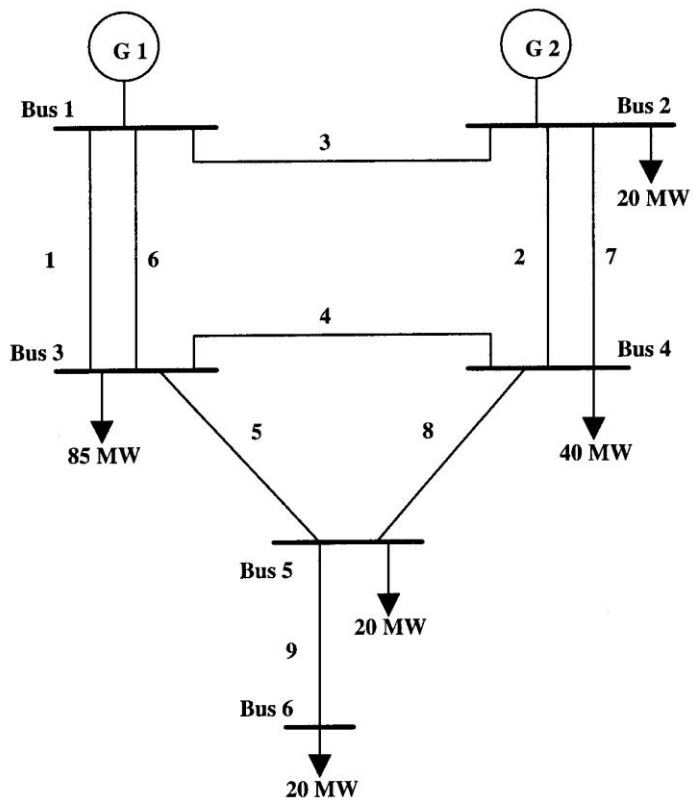


Fig. 2.3 Roy Billinton Test System

Bus 6 of the RBTS is utilized in this research. The distribution network at Bus 6 is a typical radial network with agricultural, commercial, small industrial and residential customers. Each load point consists of only one particular customer sector. The distribution system of Bus 6 consists of 4 main feeders and 64 sub-feeders with 40 load points (LP). There is a circuit breaker at the beginning of each feeder and most laterals have a step down transformer. Feeders 1 and 2 can be connected together if required via a normally open disconnect as shown in Fig.2.4.

The load points in Feeder 1 and 2 consist of Residential customers only. The total number of customers is 1733 and the combined load is 2.42 MW.

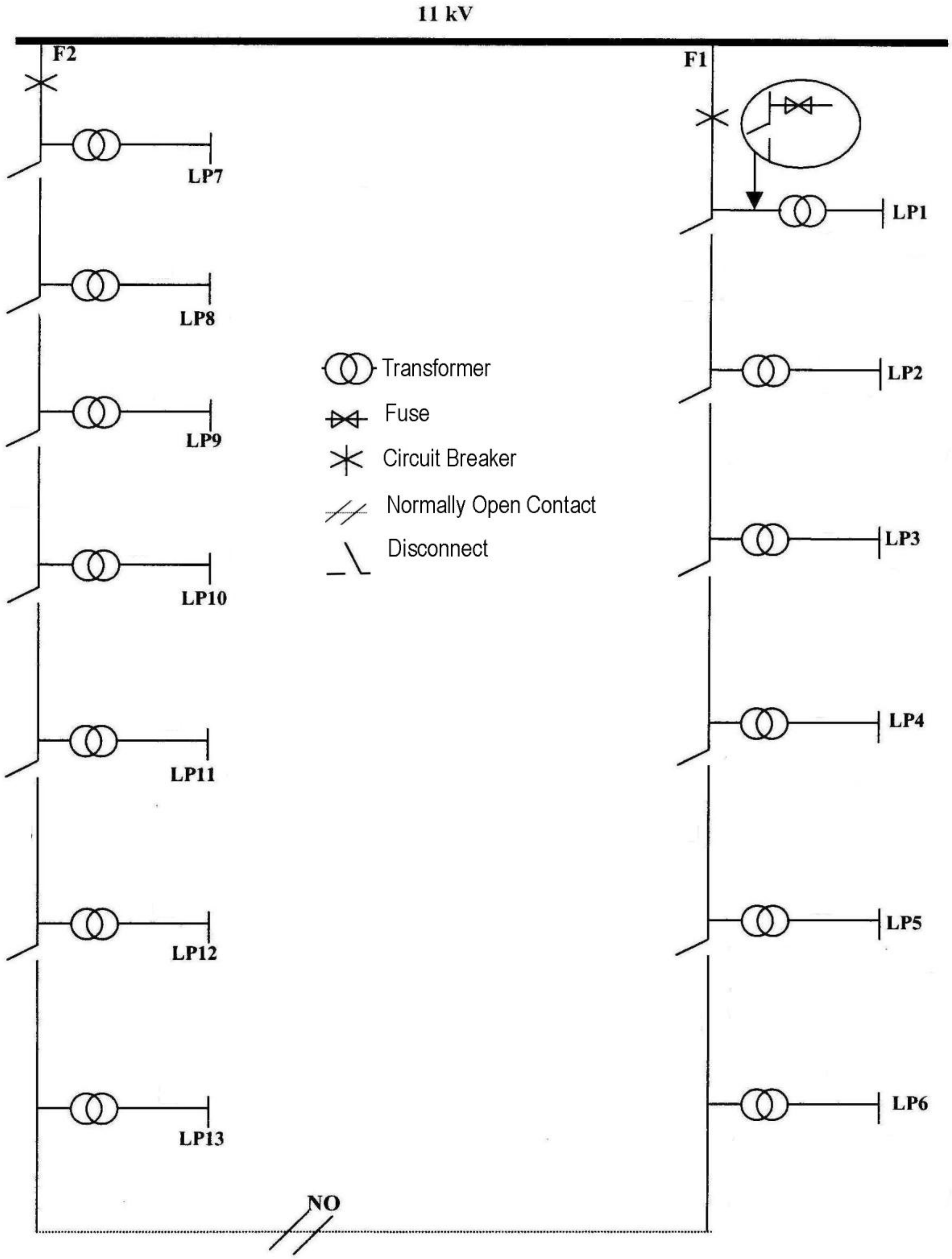


Fig. 2.4 Feeder 1 and 2 on Bus 6 of the RBTS

Feeder 3 consists of only four load points. These load points are either commercial or industrial sector customers for a total load of 3.48 MW. The step-down transformers are assumed to be owned by the customers and are not the responsibility of the utility.

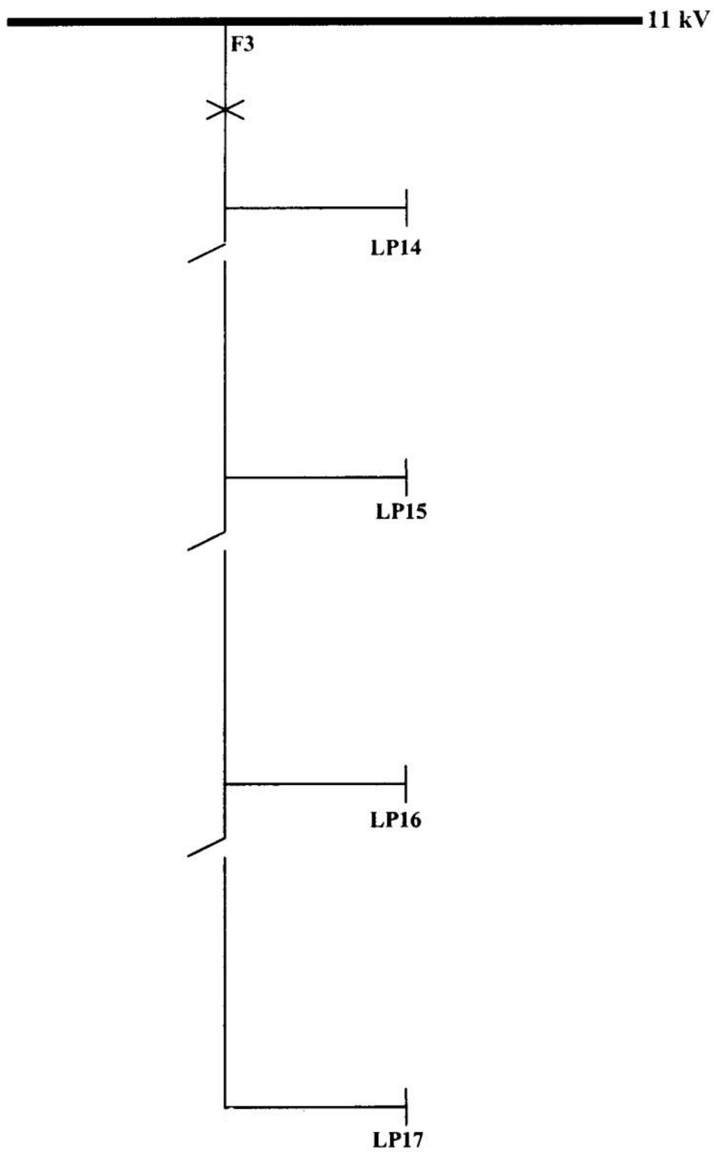


Fig. 2.5: Feeder 3 of Bus 6 of the RBTS

Feeder 4 is shown in Fig 2.6. The load is a combination of residential and agricultural customers. The total load is 4.815 MW and the total number of customers connected to Feeder 4 is 1183.

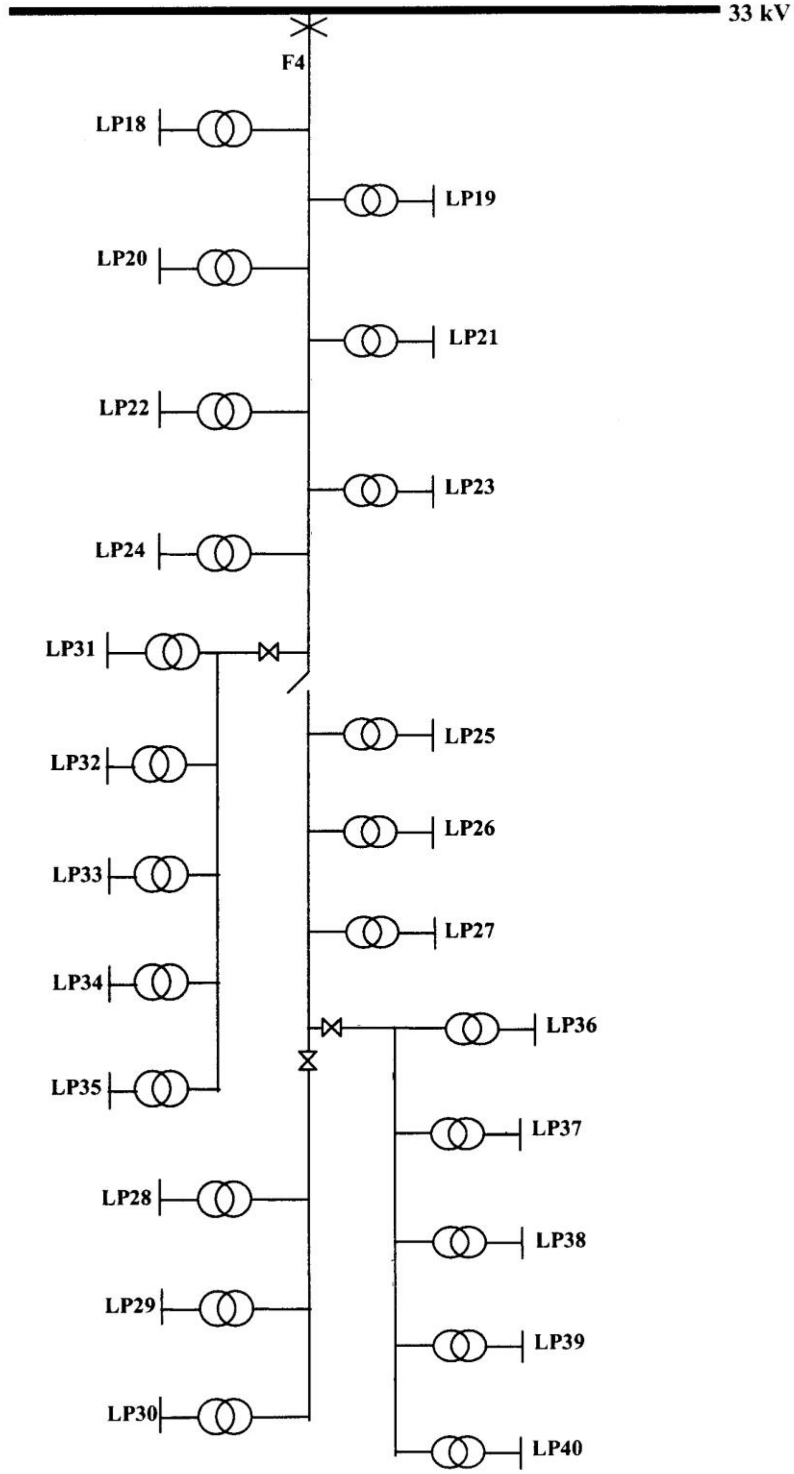


Fig. 2.6: Feeder 4 of Bus 6 of the RBTS

## 2.5 Reliability Cost/Worth Analysis

The reliability of the system can be increased by investing more capital in infrastructure. However, an optimum balance has to be achieved in terms of investment and reliability of the system. Reliability cost/worth assessment determines this optimum level of service reliability. Customer interruption costs are used as a substitute in the assessment of reliability worth in power systems [28]. Reliability cost/worth is evaluated by calculating the costs associated with the investment in the system for various configurations and the corresponding reliability worth at the respective load points. The benefits resulting from the incremental cost of reliability need to be considered along with the allocation of the investment in capital and operations to obtain the optimum reliability level.

Reliability worth can be assessed by evaluating the cost of customer losses due to service interruptions [2, 5]. The customer outage cost decreases with increase in investment. The total cost is the summation of the customer outage costs and the investment costs made to increase the level of service reliability. The optimum level of reliability occurs at the lowest total cost. The power system planner can thus design the system based on this approach to get the optimum reliability at affordable costs.

The expected annual interruption costs are calculated using customer damage functions. These parameters define the costs of interruption as a function of the interruption duration. Thus, the product of the customer damage function and probability density function of the interruption duration will result in the interruption cost distribution. Knowledge of this provides the distribution planner with the sensitivities surrounding equipment failures and the resulting costs associated with in them.

This research work focuses on exploring the variation in expected customer interruption cost using analytical and time-sequential Monte-Carlo simulation techniques. It also focuses on the effect of repair duration distributions on expected customer costs and distribution system reliability indices.

### 2.5.1 Customer Damage Function

Customer interruption costs provide a good perspective on the reliability of the power system. Customer interruption costs can be represented by customer damage functions (CDF). The CDF can be determined for a group of customers belonging to particular standardized industrial classifications (SIC) [1]. In these cases, the customer damage functions are referred to as individual customer damage functions (ICDF). All the customer costs of a given sector combined result in the sector customer damage function (SCDF).

The customer interruption cost associated with a particular interruption depends on the composition of the load point. If the load point consists of only a single customer, then the interruption cost is completely dependent upon the customer's cost characteristics. Load points consisting of multiple customers have cost functions which are aggregates of each individual customer at each load point.

The sector CDFs used in this research work are shown as demand normalized values ($/kW) in Table 2.1 [1].

Table 2.1: Sector interruption cost estimates (CDF) in $/kW

| User Sector | 1 min | 20 min | 1 hr | 4 hr | 8 hr |
|---|---|---|---|---|---|
| Industrial | 1.625 | 3.868 | 9.085 | 25.163 | 55.808 |
| Commercial | 0.381 | 2.969 | 8.552 | 31.317 | 83.008 |
| Agricultural | 0.060 | 0.343 | 0.649 | 2.064 | 4.120 |
| Residential | 0.001 | 0.093 | 0.482 | 4.914 | 15.690 |

Due to the lack of available information, the interruption costs at durations beyond those given in Table 2.1 need to be reasonably estimated. Linear interpolation in the logarithmic scale is done for interruption costs between the specified durations in Table 2.1 as shown in (2.12).

$$logC(d) = \frac{1}{(logd_8 - logd_4)} * [logC(d_8) * \{logd - logd_4\} - logC(d_4) * \{logd - logd_8\}] \tag{2.12}$$

where,

$C(d_8)$ is the interruption cost for duration, $d_8$, is 8 hours

$C(d_4)$ is the interruption cost for duration, $d_4$, is 4 hours

C(d) is the interruption cost to be determined for duration d.

Similarly, for interruption costs beyond the maximum duration in Table 2.1, a linear extrapolation is done as shown in (2.13)

$$C(d) = \frac{1}{(d_8 - d_4)} * [C(d_8) - C(d_4)] * (d - d_8) + C(d_8) \qquad (2.13)$$

where,

$C(d_8)$ is the interruption cost for duration, $d_8$, is 8 hours

$C(d_4)$ is the interruption cost for duration, $d_4$, is 4 hours

C(d) is the interruption cost to be determined for duration d.

### 2.5.2 Composite Customer Damage Function

A composite customer damage function (CCDF) is created by aggregating the sector CDF data. Table 2.2 shows the load composition based on annual peak demand for Bus 6 of the Roy Billinton Test System (RBTS) used in this research work. It is assumed that there is proportional distribution of load curtailment across all the sectors shown in Table 2.1.

Table 2.2: Load composition for the system based on annual peak demand

| User Sector | Sector Peak (MW) | Sector Peak (%) |
|---|---|---|
| Industrial | 3.05 | 15.25 |
| Commercial | 1.70 | 8.5 |
| Agricultural | 7.40 | 37.0 |
| Residential | 7.85 | 39.25 |
| TOTAL | 20 | 100 |

Table 2.3 shows the CCDF obtained for the system from the sector CDF using the load composition for the system from Table 2.2.

Table 2.3: System CCDF and sector CDF ($/kW)

| User Sector / Time (min) | 1 | 20 | 60 | 240 | 480 |
|---|---|---|---|---|---|
| Industrial | 1.625 | 3.868 | 9.085 | 25.163 | 55.808 |
| Commercial | 0.381 | 2.969 | 8.552 | 31.317 | 83.008 |
| Agricultural | 0.06 | 0.343 | 0.649 | 2.064 | 4.12 |
| Residential | 0.001 | 0.093 | 0.482 | 4.914 | 15.69 |
| CCDF | 0.303 | 1.006 | 2.542 | 9.192 | 23.249 |

Fig.2.7 shows each sector CDF along with the system CCDF in the logarithmic scale.

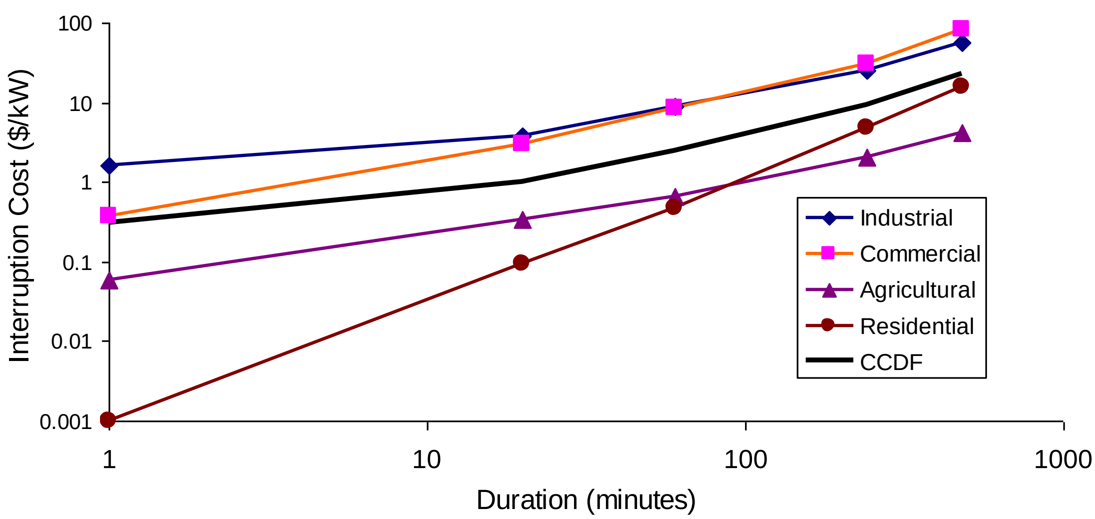


Fig. 2.7 Sector CDFs and System CCDF

Similarly, the Feeder CCDF can be obtained from sector CDF by using the load composition in each individual feeder. Feeder 1 and 2 of Bus 6 contain residential sector customers. Feeder 3 contains commercial and industrial sector while Feeder 4 contains agricultural and residential sector customers. Table 2.4 shows the load composition by percentage at each of these feeders.

Table 2.4: Load composition by percentage for each feeder of Bus 6

| User Sector | Feeder 1 (%) | Feeder 2 (%) | Feeder 3 (%) | Feeder 4 (%) |
|---|---|---|---|---|
| Industrial | 0 | 0 | 64.21 | 0 |
| Commercial | 0 | 0 | 35.79 | 0 |
| Agricultural | 0 | 0 | 0 | 67.72 |
| Residential | 100 | 100 | 0 | 32.28 |

Table 2.5 shows the Feeder CCDF for each of the feeders of Bus 6 obtained using Tables 2.3 and 2.4

Table 2.5: Feeder CCDF ($/kW)

| CCDF / Time (min) | 1 | 20 | 60 | 240 | 480 |
|---|---|---|---|---|---|
| Feeder 1 | 0.001 | 0.093 | 0.482 | 4.914 | 15.69 |
| Feeder 2 | 0.001 | 0.093 | 0.482 | 4.914 | 15.69 |
| Feeder 3 | 1.18 | 3.55 | 8.89 | 27.37 | 65.54 |
| Feeder 4 | 0.04 | 0.26 | 0.60 | 2.98 | 7.86 |

### 2.5.3 Expected Customer Cost (ECOST)

Customer damage functions are important elements in the evaluation of expected customer costs. Sector customer damage function can be applied to represent customer groups and the expected customer costs thus obtained will represent the costs associated with the respective sector.

The expected interruption cost at any load point is given by

$$ECOST = \frac{\sum_{i=1}^{m} [L*C(d_i)]}{N} \; (\$/yr) \qquad (2.14)$$

where, L is the peak load at the load point, $C(d_i)$ is the cost of the energy not supplied during duration d and is obtained from the customer damage function (CDF) at the load point, m is the number of interruptions and N is the simulation period.

## 2.6 Standard Probability Distributions

A power system is stochastic in nature. The occurrence of component failure in the system is random and can result in a power outage. Generally, utilities keep records of failure and duration events and analyzing such data provides event probability distributions. This research will analyze the effect of repair duration distributions on expected customer costs and distribution reliability indices. The following standard probability distributions [18] associated with repair durations are considered:

### 2.6.1 Normal Distribution

The normal distribution is also referred to as the Gaussian distribution. The probability density function of a normal distribution is,

$$f(t) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(t-\mu)^2}{2\sigma^2}} \qquad (2.15)$$

where, $\mu$ and $\sigma^2$ are the mean and the variance of the normal distribution.

### 2.6.2 Exponential Distribution

The probability density function of an exponential distribution is,

$$f(t) = \lambda e^{-\lambda t} \qquad (2.16)$$

where, $0<t<\infty$ and $\lambda$ is the failure rate.

### 2.6.3 Rayleigh Distribution

The probability density function of a Rayleigh distribution is,

$$f(t) = \frac{t}{\sigma^2} e^{-\frac{t^2}{2\sigma^2}} \tag{2.17}$$

where, $0 < t < \infty$ and $\sigma^2$ is the variance of the distribution.

### 2.6.4 Weibull Distribution

The probability density function of the Weibull distribution is defined as,

$$f(t) = \frac{\beta t^{\beta-1}}{\alpha^{\beta}} exp\left[-\left(\frac{t}{\alpha}\right)^{\beta}\right] \tag{2.18}$$

where, $t \geq 0$, scale parameter $\alpha \geq 0$, and shape parameter $\beta \geq 0$.

For $\beta = 1$, the equation reduces to that of an Exponential distribution.

For $\beta = 2$, the equation is identical to that of a Rayleigh distribution.

For $\beta = 3.5$, the equation approximates to a Normal distribution.

Thus, the Weibull distribution can be used to represent a number of important distributions. This property of the Weibull distribution has been utilized to generate various repair duration distributions used with the Monte-Carlo simulation technique.

The expected value of the Weibull distribution is defined as,

$$E(t) = \int_0^{\infty} t * \frac{\beta t^{\beta-1}}{\alpha^{\beta}} exp\left[-\left(\frac{t}{\alpha}\right)^{\beta}\right] dt \tag{2.19}$$

$$E(t) = \alpha\Gamma\left(\frac{1}{\beta}+1\right) \tag{2.20}$$

where, $\Gamma$ is the gamma function and is defined as,

$$\Gamma(\gamma) = \int_0^{\infty} t^{\gamma-1} e^{-t}\, dt \qquad (2.21)$$

and for integer values of γ, (2.21) reduces to

$$\Gamma(\gamma) = (\gamma - 1)! \qquad (2.22)$$

The expected value of the distribution is the average repair duration of a component in the system. Hence, for different shape parameter values, corresponding scale parameter values can be obtained using (2.20) to (2.22) when the average repair durations of the components are given.

If U is the random variate drawn from the uniform distribution in the interval of (0,1), then the variate X has a Weibull distribution as shown in (2.23) with parameters α and β, where α is the scale parameter and β is the shape parameter.

$$X = \alpha\left(-lnU\right)^{\frac{1}{\beta}} \qquad (2.23)$$

## 2.7 Summary

This chapter provides an introduction to electric distribution systems, including meshed and radial systems and various components in a distribution system. The basic load point and system reliability indices are also introduced together with the equations used to evaluate these indices for a distribution system.

Reliability cost/worth analysis is an essential concept to evaluate the benefit or cost associated with the reliability of the system. The customer damage functions (CDF) show the relationship between the costs and the outage durations for a particular sector of customer. The significance of CDF and its application in reliability cost/worth analysis is explained in this chapter.

The Roy Billinton Test System used for this research work is also illustrated. Various standard probability distributions applied in the research are introduced. These probability distributions are applied for repair durations and the effect of this on the expected customer cost and the reliability indices is analyzed in subsequent chapters.

# CHAPTER 3
# DISTRIBUTION SYSTEM RELIABILITY EVALUATION TECHNIQUES

## 3.1 Introduction

Reliability analysis of a distribution system can be accomplished either through the application of analytical techniques or Monte-Carlo simulation techniques. In analytical methods, the system is represented by a mathematical model. The reliability indices are then evaluated from this model using mathematical solutions which are generally based on failure mode and effect analysis (FMEA) [1]. The reliability indices thus calculated are usually average or expected values.

The time-sequential Monte-Carlo simulation technique can be used on any system that is stochastic in nature. The up and down states are modeled using a random number generator and the probability distributions of the component failure and restoration processes. A sequence thus generated is used to study the distributions surrounding the expected values of the reliability indices.

This chapter illustrates the application of analytical method and simulation method on a simple test system. A program developed utilizing the time-sequential Monte-Carlo simulation technique is also explained here.

## 3.2 Analytical Technique

The distribution system is represented as a mathematical model for analytical techniques to be applied. Most analytical techniques are based on failure mode and effect analysis (FMEA). A failure in any component between the supply point and load point will result in outages. The minimal cut sets of the system directly relate to the failure modes of the system [1,18]. Failure mode and effect analysis technique is used to evaluate the expected values of basic load point and system reliability indices.

As noted in Chapter 2, the Bus 6 of the RBTS is a distribution system consisting of 4 main feeder lines as shown in Fig 3.1. Feeders 1 and 2 serve residential customers and are connected together through a normally open sectionalizing switch. Feeder 3 is a short feeder serving commercial and industrial customers. Feeder 4 is a relatively long feeder with 3 sub feeders serving residential and agricultural customers.

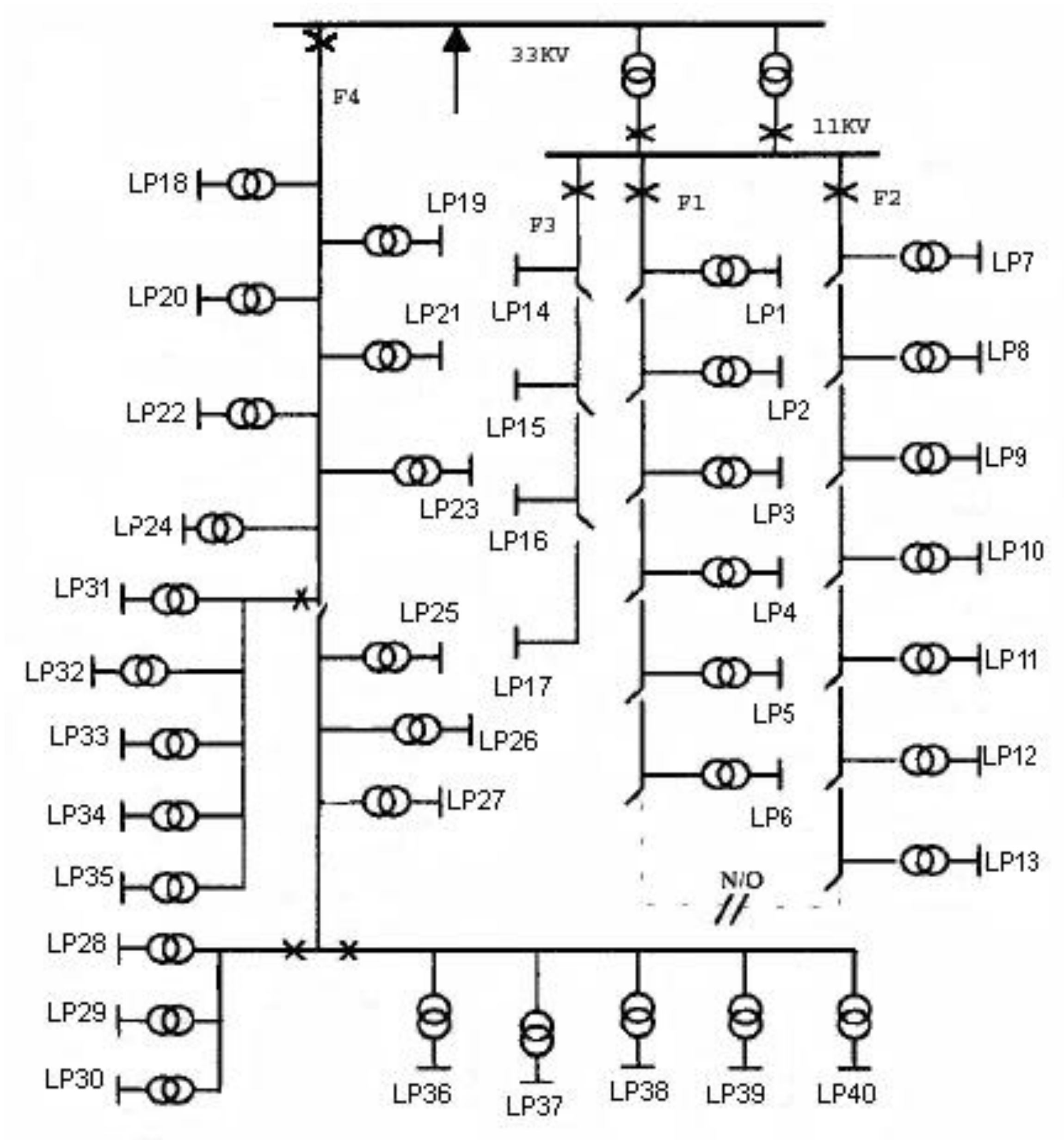


Fig. 3.1 Bus 6 of the RBTS

Feeder 3 of Bus 6 of the RBTS is considered to illustrate the principles of FMEA. It consists of 4 main sections M14 to M17, and 4 lateral sections L14 to L17. The type and number of customers at each of the load points in Feeder 3 are as shown in Fig 3.2

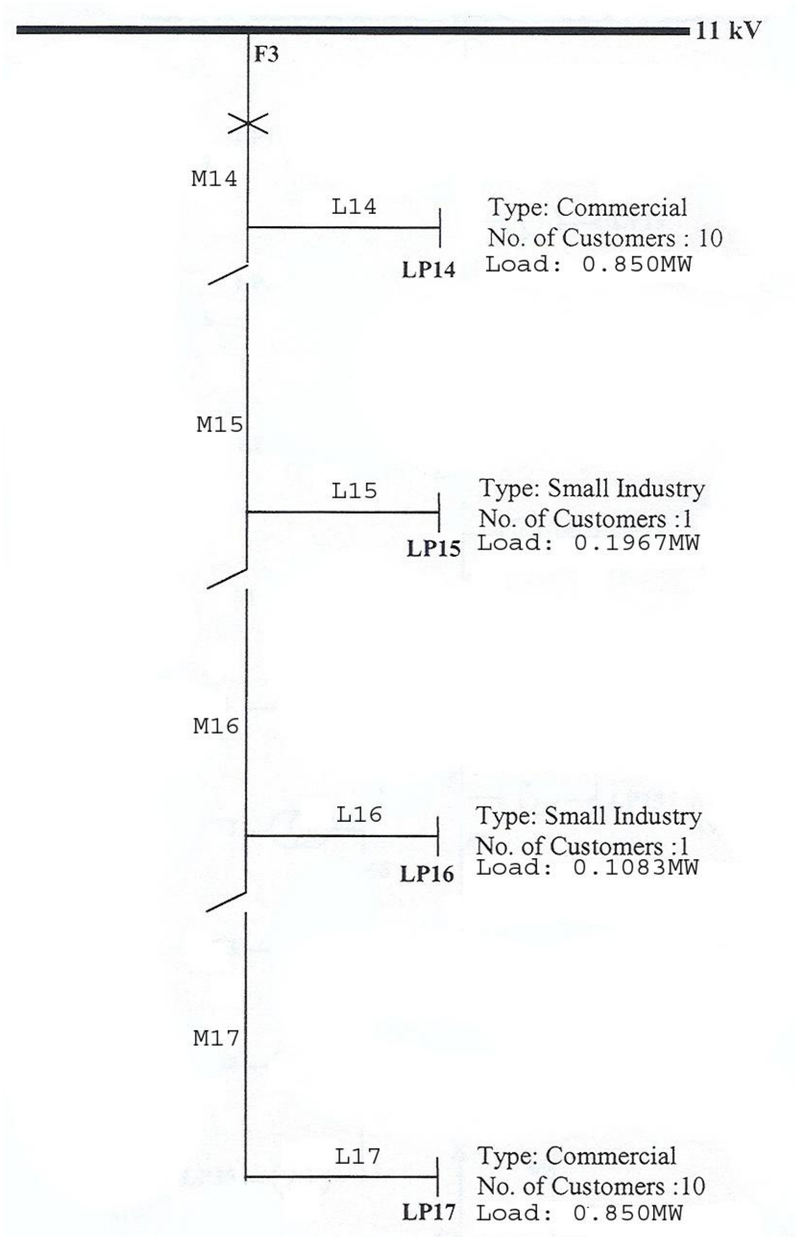


Fig. 3.2 Feeder 3 of Bus 6, with type and number of customers and load at its load points

It was assumed that the circuit breaker never fails and the step-down transformers are owned by the customers and are hence not the responsibility of the utility. The repair time for both the main and lateral sections is 5.0 hours and switching time is 1.0 hour. The load point indices – average failure rate λ, average outage time r and average annual outage time or unavailability U – are calculated using (2.1) to (2.3) for LP14 to LP17 of Feeder 3 as shown in the Table 3.1.

Table 3.1 Load point indices for Feeder 3

| | LP14 | | | LP15 | | |
|---|---|---|---|---|---|---|
| *Main Section* | *λ(f/yr)* | *r(hr)* | *U(hr/yr)* | *λ(f/yr)* | *r(hr)* | *U(hr/yr)* |
| 14 | 0.0487 | 5 | 0.2435 | 0.0487 | 5 | 0.2435 |
| 15 | 0.0520 | 1 | 0.0520 | 0.0520 | 5 | 0.2600 |
| 16 | 0.0390 | 1 | 0.0390 | 0.0390 | 1 | 0.0390 |
| 17 | 0.0487 | 1 | 0.0487 | 0.0487 | 1 | 0.0487 |
| *Lateral Section* | | | | | | |
| 14 | 0.0390 | 5 | 0.1950 | | | |
| 15 | | | | 0.0487 | 5 | 0.2437 |
| 16 | | | | | | |
| 17 | | | | | | |
| TOTAL | 0.2274 | 2.5426 | 0.5782 | 0.2371 | 3.5208 | 0.8349 |

| | LP16 | | | LP17 | | |
|---|---|---|---|---|---|---|
| *Main Section* | *λ(f/yr)* | *r(hr)* | *U(hr/yr)* | *λ(f/yr)* | *r(hr)* | *U(hr/yr)* |
| 14 | 0.0487 | 5 | 0.2435 | 0.0487 | 5 | 0.2435 |
| 15 | 0.0520 | 5 | 0.2600 | 0.0520 | 5 | 0.2600 |
| 16 | 0.0390 | 5 | 0.1950 | 0.0390 | 5 | 0.1950 |
| 17 | 0.0487 | 1 | 0.0487 | 0.0487 | 5 | 0.2435 |
| *Lateral Section* | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | 0.0520 | 5 | 0.2600 | | | |
| 17 | | | | 0.0390 | 5 | 0.1950 |
| TOTAL | 0.2404 | 4.1897 | 1.0072 | 0.2274 | 5 | 1.1370 |

The system indices - SAIFI, SAIDI, CAIDI, IOR, ASIFI, ASIDI – can then be calculated from the load point indices and the number of customers and load connected at the load point. Table 3.2 shows the system indices for Feeder 3 of Bus 6 of the RBTS.

Table 3.2 System Indices for Feeder 3

| | |
|---|---|
| SAIFI | 0.228434 |
| SAIDI | 0.863370 |
| CAIDI | 3.779517 |
| ASIFI | 0.234402 |
| ASIDI | 0.882329 |
| IOR | 0.999901 |

The basic load point and system indices thus calculated are expected values. Hence, the analytical approach does not provide any information on the variation of the value about the mean.

### 3.3 Monte Carlo Simulation Technique

A power system is stochastic in nature and therefore Monte Carlo simulation techniques can be applied for reliability evaluation of a power system. There are primarily two types of Monte Carlo simulation – state sampling and time sequential techniques. In the state sampling technique, the states of all the components in the power system are analyzed after the completion of the simulation period. The effect of each state of a component on the power system is analyzed and the reliability indices are evaluated.

In the time sequential Monte Carlo simulation technique, the effect of the events of each component on the power system is chronologically analyzed. The reliability indices are then calculated. This technique has been applied in this research work to evaluate the reliability indices. A computer program has been developed for this research work utilizing this approach.

### 3.3.1 Generation of Random Numbers

Since perfect random numbers are not attainable using a computer program, pseudo-random numbers are used. The built-in random number generator of Visual C++ has been used to create uniformly distributed pseudo-random numbers in the interval [0, 1]. A seed is applied to generate the random numbers so as to be able to duplicate the results obtained. These pseudo-random numbers are used to get the times to failure (TTF) and repair time (RT) for each component.

The inverse transform method [18] can be used to convert the uniform distribution of random numbers into an exponential distribution of failure times. The cumulative probability distribution function for the exponential distribution (2.16) is:

$$U = F_T(t) = 1 - e^{-\lambda t} \qquad (3.1)$$

where, $\lambda$ is the failure rate of a component and U is a uniformly distributed random variable over the interval [0, 1].

Thus, solving for T:

$$T = -(1/\lambda) \ln (1 - U) \qquad (3.2)$$

Since (1-U) is distributed the same way as U, then:

$$T = -(1/\lambda) \ln (U) \qquad (3.3)$$

where, U is uniformly distributed and T is exponentially distributed.

Similarly, a uniformly distributed random variate in the interval of [0, 1] can be converted into a Weibull distribution as shown in (2.23). The shape parameter values can then be specified to obtain other distributions from Weibull distribution.

### 3.3.2 Monte Carlo simulation procedure

The algorithm used to develop the computer program to determine the distribution system reliability indices using Monte Carlo simulation consists of the following steps:

Step1: Generate random number for each component in the system

Step 2: Convert these random numbers into times to failure (TTF) according to the probability distribution.

Step 3: Find the element with minimum TTF

Step 4: Generate a random number and convert this into repair time (RT) for this element according to the probability distribution chosen.

Step 5: Generate another random number and convert this into switching time (ST) according to the probability distribution if applicable. For this research work, switching time is a fixed value of 1 hour.

Step 6: Find the load points that are affected by the failure of this element considering the configuration and status of breakers, disconnects, fuses and alternate supply and record a failure for each of these load points.

Step 7: Determine the failure duration depending upon the configuration and status of breakers, disconnects, fuses and alternate supply and record the outage duration for each failed load point.

Step 8: Generate a random number and convert this into TTF for the failed element.

Step 9: Go back to Step 3 if the simulation time is less than the mission time. Otherwise, go to Step 10.

Step 10: Calculate the average value of the load point failure rate and failure duration for the sample years.

Step 11: Calculate the system indices for the sample years

Step 12: Return to Step 1 if the simulation time is less that the total simulation period. Otherwise, output the results.

The simulation program developed evaluates the reliability indices for a general radial distribution system. The following modeling assumptions are made to simplify the program:

1. Circuit breakers are assumed to work instantly and without any failures or delay.
2. Alternate supply is assumed to be available whenever needed and can supply all necessary power to the load. No transfer load restriction exists.
3. Fuses are assumed to work without failures.
4. No common mode failures occur.
5. No busbar failures occur.
6. The same probability distributions are assigned to the same type of components.

### 3.3.3 Application of the Monte-Carlo simulation program

The load point and system indices for Feeder 3 of Bus 6 of the RBTS obtained using the simulation program are shown in Tables 3.3 and 3.4. These values are very close to those obtained using the analytical technique in Tables 3.1 and 3.2. Section 3.4 shows a comparison of all load point and system indices for Bus 6 obtained using the analytical and Monte Carlo simulation techniques.

Table 3.3 Load point indices for Feeder 3

| Load Point (i) | Failure Rate (Occ./yr) | Ave. Repair Time (hr/Occ.) | Unavailability (hr/yr) |
|---|---|---|---|
| 14 | 0.22868 | 2.59164 | 0.59266 |
| 15 | 0.23624 | 3.56313 | 0.84176 |
| 16 | 0.23956 | 4.21623 | 1.01004 |
| 17 | 0.22720 | 4.99657 | 1.13522 |

Table 3.4 System indices for Feeder 3

| | |
|---|---|
| SAIFI | 0.228845 |
| SAIDI | 0.869573 |
| CAIDI | 3.799834 |
| ASIFI | 0.234026 |
| ASIDI | 0.888064 |
| IOR | 0.999901 |

### 3.3.4 Convergence of the Monte-Carlo simulation program

The expected value of any reliability index calculated using the Monte Carlo simulation technique should be similar to that obtained using the analytical technique when the analysis is conducted over a sufficient length of simulation time. The convergence of the indices to their expected values shows the proper functioning of the computer program. The System Average Interruption Frequency Index (SAIFI) for the entire distribution system of Bus 6 of the RBTS has been used to check for the convergence of the simulation. No stopping rules have been created. Instead, the convergence of SAIFI has been analyzed over a large simulation period. Fig 3.3 shows the convergence of SAIFI for various random numbers seeds. The pseudo-random numbers thus generated also need to be non-repetitive during the simulation period. Fig 3.3 shows that a seed value of 9 results in SAIFI values that start to converge at around a simulation period of 50000 sample years. The convergence holds as the simulation period is increased to 150000 sample years.

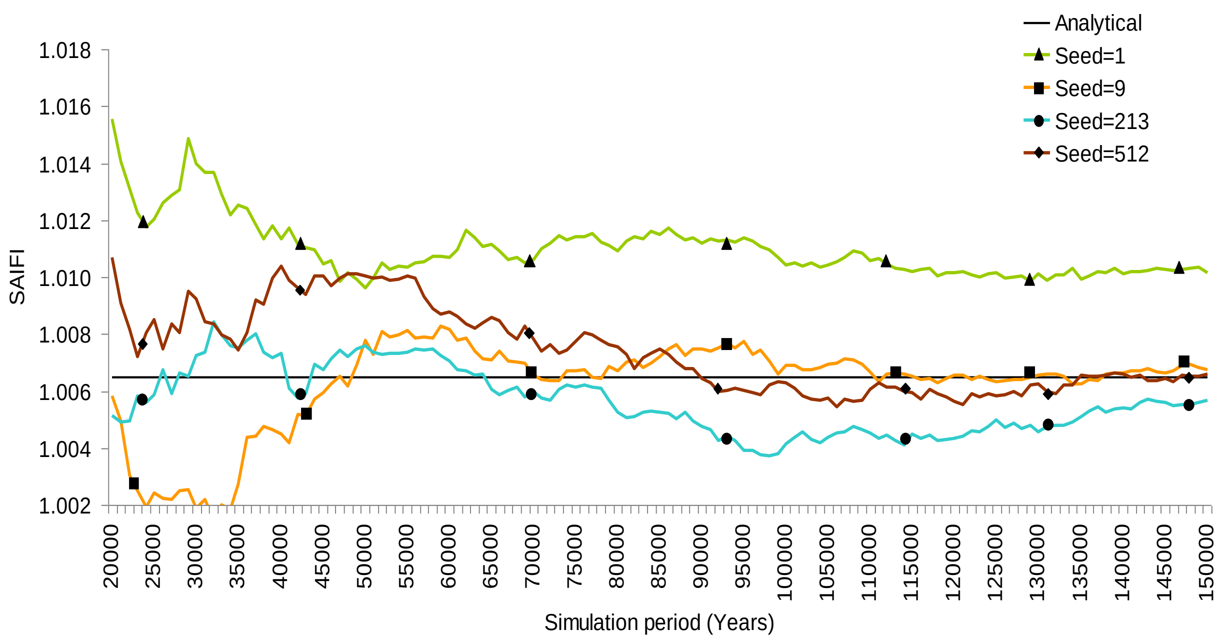


Fig. 3.3 Convergence of SAIFI for various random number seeds

### 3.4 Reliability Analysis of Bus 6 of the RBTS

The configuration of the RBTS distribution system at Bus 6 is shown in Fig 3.1. The data of main and lateral sections including load point information for Bus 6 are shown in Appendix A. Tables 3.5 and 3.6 lists the comparison of the load point indices and system indices for Bus 6 obtained using the analytical and Monte Carlo simulation techniques.

Table 3.5 Comparison of load point indices for Bus 6

| | Failure Rate (Occ./yr) | | Ave. Repair Time (hr/Occ.) | | Unavailability (hr/yr) | |
|---|---|---|---|---|---|---|
| Load Point (i) | (A) | (S) | (A) | (S) | (A) | (S) |
| 1 | 0.33010 | 0.33162 | 2.47168 | 2.45385 | 0.81590 | 0.81375 |
| 2 | 0.34310 | 0.34388 | 2.45439 | 2.44876 | 0.84210 | 0.84208 |
| 3 | 0.33985 | 0.34284 | 2.54421 | 2.56967 | 0.86465 | 0.88099 |
| 4 | 0.33010 | 0.33382 | 2.47168 | 2.48771 | 0.81590 | 0.83045 |
| 5 | 0.33985 | 0.34126 | 2.43004 | 2.44324 | 0.82585 | 0.83378 |
| 6 | 0.33010 | 0.33300 | 2.51166 | 2.47339 | 0.82910 | 0.82364 |
| 7 | 0.36915 | 0.37024 | 2.31654 | 2.34894 | 0.85515 | 0.86967 |
| 8 | 0.37240 | 0.37072 | 2.44415 | 2.44042 | 0.91020 | 0.90471 |
| 9 | 0.37240 | 0.37142 | 2.33996 | 2.33755 | 0.87140 | 0.86821 |
| 10 | 0.35940 | 0.35854 | 2.24374 | 2.25329 | 0.80640 | 0.80789 |
| 11 | 0.36915 | 0.36974 | 2.45740 | 2.47989 | 0.90715 | 0.91691 |
| 12 | 0.35940 | 0.35844 | 2.35170 | 2.36412 | 0.84520 | 0.84740 |
| 13 | 0.36915 | 0.36816 | 2.31654 | 2.32934 | 0.85515 | 0.85757 |
| 14 | 0.22740 | 0.22864 | 2.54266 | 2.60060 | 0.57820 | 0.59460 |
| 15 | 0.23715 | 0.23622 | 3.52077 | 3.56628 | 0.83495 | 0.84243 |
| 16 | 0.24040 | 0.23970 | 4.18968 | 4.23888 | 1.00720 | 1.01606 |
| 17 | 0.22740 | 0.22702 | 5.00000 | 5.00907 | 1.13700 | 1.13716 |
| 18 | 1.67250 | 1.67376 | 3.31928 | 3.31656 | 5.55150 | 5.55113 |
| 19 | 1.67250 | 1.67356 | 3.31928 | 3.31285 | 5.55150 | 5.54425 |
| 20 | 1.67250 | 1.67278 | 3.31928 | 3.31078 | 5.55150 | 5.53821 |
| 21 | 1.67250 | 1.67376 | 3.31928 | 3.32237 | 5.55150 | 5.56085 |
| 22 | 1.67250 | 1.67344 | 3.31928 | 3.31169 | 5.55150 | 5.54191 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | 1.71150 | 1.71422 | 3.35758 | 3.35375 | 5.74650 | 5.74907 |
| 24 | 1.72125 | 1.72302 | 3.36688 | 3.36085 | 5.79525 | 5.79081 |
| 25 | 1.67250 | 1.67366 | 5.04484 | 5.05702 | 8.43750 | 8.46374 |
| 26 | 1.71150 | 1.71146 | 5.04382 | 5.06023 | 8.63250 | 8.66038 |
| 27 | 1.67250 | 1.67370 | 5.04484 | 5.05654 | 8.43750 | 8.46313 |
| 28 | 2.22500 | 2.22838 | 5.03371 | 5.03971 | 11.20000 | 11.23040 |
| 29 | 2.22500 | 2.22912 | 5.03371 | 5.04401 | 11.20000 | 11.24370 |
| 30 | 2.22500 | 2.23090 | 5.03371 | 5.04572 | 11.20000 | 11.25650 |
| 31 | 2.53700 | 2.53782 | 3.89200 | 3.88528 | 9.87400 | 9.86014 |
| 32 | 2.58900 | 2.58776 | 3.91425 | 3.90164 | 10.13400 | 10.09650 |
| 33 | 2.52200 | 2.53672 | 3.85567 | 3.87980 | 9.72400 | 9.84197 |
| 34 | 2.52200 | 2.53562 | 3.85567 | 3.88120 | 9.72400 | 9.84124 |
| 35 | 2.52200 | 2.53628 | 3.85567 | 3.87767 | 9.72400 | 9.83486 |
| 36 | 2.51100 | 2.51708 | 5.02987 | 5.02658 | 12.63000 | 12.65230 |
| 37 | 2.55975 | 2.56686 | 5.02930 | 5.03432 | 12.87375 | 12.92240 |
| 38 | 2.49600 | 2.51728 | 5.00000 | 5.03099 | 12.48000 | 12.66440 |
| 39 | 2.51100 | 2.51750 | 5.02987 | 5.03174 | 12.63000 | 12.66740 |
| 40 | 2.49600 | 2.51702 | 5.00000 | 5.02880 | 12.48000 | 12.65760 |

Table 3.6 Comparison of system indices for Bus 6

| | | Feeder 1 | Feeder 2 | Feeder 3 | Feeder 4 | System |
|---|---|---|---|---|---|---|
| SAIFI | (A) | 0.335511 | 0.367299 | 0.228434 | 1.976799 | 1.006066 |
| | (S) | 0.337655 | 0.366951 | 0.228845 | 1.979710 | 1.007680 |
| SAIDI | (A) | 0.832602 | 0.863826 | 0.863370 | 8.214516 | 3.815494 |
| | (S) | 0.836577 | 0.865891 | 0.869573 | 8.234640 | 3.825360 |
| CAIDI | (A) | 2.481594 | 2.351836 | 3.779517 | 4.155464 | 3.792490 |
| | (S) | 2.477609 | 2.359691 | 3.799834 | 4.159518 | 3.796205 |
| ASIFI | (A) | 0.335486 | 0.367166 | 0.234402 | 2.130539 | 1.295925 |
| | (S) | 0.337620 | 0.366811 | 0.234026 | 2.136870 | 1.299470 |
| ASIDI | (A) | 0.831909 | 0.864023 | 0.882329 | 9.168927 | 5.403040 |
| | (S) | 0.835409 | 0.865963 | 0.888064 | 9.222290 | 5.434140 |
| IOR | (A) | 0.999905 | 0.999901 | 0.999901 | 0.999062 | 0.999564 |
| | (S) | 0.999905 | 0.999901 | 0.999901 | 0.999060 | 0.999563 |

### 3.5 Summary

This chapter briefly introduces the analytical and time sequential Monte Carlo simulation techniques. The failure mode and effect analysis used in analytical techniques is illustrated by applying it on Feeder 3 of Bus 6 of the RBTS.

The concept involved in developing a computer simulation program that utilizes the time sequential Monte Carlo simulation technique to evaluate load point and system indices is described in this chapter. The technique to convert a uniformly distributed random number to another distribution is also explained. This is important to generate repair duration distributions for this research work. The convergence of SAIFI to that obtained using the analytical technique is also demonstrated.

A comparison of the load point and system indices for Bus 6 of the RBTS using both analytical and Monte Carlo simulation techniques is also illustrated in this chapter.

# CHAPTER 4
# VARIATION IN ECOST USING ANALYTICAL AND TIME SEQUENTIAL TECHNIQUES

## 4.1 Introduction

The analytical and Monte Carlo simulation techniques utilize different data to calculate the ECOST at the load points and in the total system. The analytical techniques applied follow the Failure Mode and Effect Analysis while the time sequential Monte Carlo simulation technique is used as described in Chapter 3 and the general process of applying these techniques are detailed in Reference [1]. These various techniques are analyzed on a case by case basis. The results are then compared to determine the variation in the expected customer cost values.

Expected values are obtained using the analytical techniques. The respective sector CDF and CCDF used are shown in Table 2.3 in Chapter 2. The expected customer cost values are obtained at the system and individual load point levels. The simulation period chosen is 150,000 years and the random number generator seed used is 9 for the Monte Carlo simulation technique. The repair duration distributions are modeled as Weibull distributions. Distributions following the hyper-exponential, exponential, normal and Rayleigh distributions can be represented by changing the shape parameter.

## 4.2 Analytical Techniques

### Case 1: Simplified Technique

The expected system interruption cost ECOST can be estimated using the total peak load at Bus 6 of the RBTS, the SAIFI for the system, and the cost associated with CAIDI using the system CCDF.

$$\text{ECOST} = \text{SAIFI} * \text{CCDF}_{\text{CAIDI}} * \text{Peak Load}$$

Table 4.1 Total expected cost using the Simplified technique

| | SAIFI *(int/cust)* | SAIDI *(hr/cust)* | CAIDI *(hr/int)* | Peak Load *(kW)* | ECOST *(k$/yr)* |
|---|---|---|---|---|---|
| SYSTEM | 1.0065 | 3.8196 | 3.7950 | 20000 | 176.2151 |

Applying a CAIDI of 3.7950 hours, the equivalent customer interruption cost using the system CCDF is 8.7541 $/kW. Thus, the ECOST for the system is 176.2151 k$/yr.

**Case 2: Modified Technique**

A more accurate value of ECOST can be obtained by calculating the ECOST at each main feeder. The SAIFI calculated at the feeder level is used and the cost associated with the corresponding CAIDI for that feeder is obtained using the Feeder CCDF.

Table 4.2 Total expected cost using the Modified technique

| | SAIFI *(int/cust)* | CAIDI *(hr/int)* | Load *(kW)* | CIC *($/kW)* | ECOST *(k$/yr)* |
|---|---|---|---|---|---|
| FEEDER 1 | 0.3355 | 2.5977 | 2052.8 | 2.3848 | 1.6425 |
| FEEDER 2 | 0.3673 | 2.3518 | 2268.8 | 2.0189 | 1.6824 |
| FEEDER 3 | 0.2284 | 3.7795 | 4750 | 26.1397 | 28.3632 |
| FEEDER 4 | 1.9778 | 4.1584 | 10928.4 | 3.1465 | 68.0095 |
| TOTAL | | | | | 99.6976 |

It can be seen that the ECOST for the system decreases to 99.6976 k$/yr. Consideration of the ECOST at the feeder levels using the corresponding SAIFI and peak load gives a more accurate estimate of the ECOST at the system level.

**Case 3: Detailed Technique using CCDF**

The ECOST at a particular load point was calculated using the system CCDF, the average failure rate and repair duration of each section and component leading to that load point. The summation of the ECOST of all the load points gives the system ECOST. Fig 4.1 shows the results of the calculation of ECOST at various load points in Bus 6 of RBTS using the system CCDF.

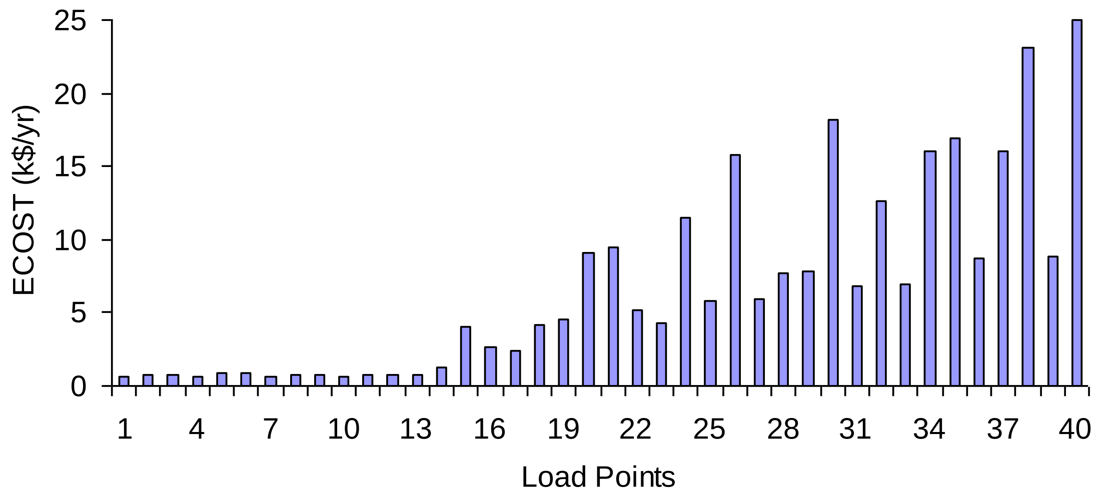


Fig. 4.1 Calculation of the load point ECOST using the system CCDF

It can be seen that the size of the peak load at the load point, position of the load point in the system and the operating scheme of the layout to that load point, i.e. the presence of disconnects, breakers, alternate supply significantly affects the load point expected costs.

The ECOST for the entire system is the summation of all the load point costs and is equal to 270.5905 k$/yr.  This is an increase of 171.42% from the ECOST calculated in Case 2 and an increase of 53.56% from Case 1.

**Case 4: Detailed Technique using sector CDF**

The ECOST can be calculated at the load points in a similar way to Case 3 using the sector customer damage functions.  The appropriate customer interruption cost is selected from the sector CDF depending upon the type of the customer at each load point.

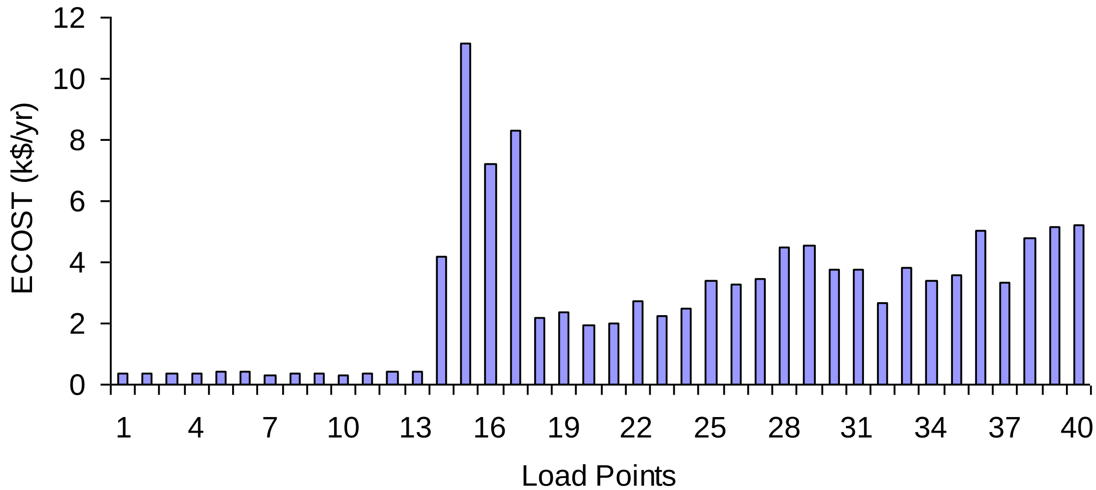


Fig. 4.2 Calculation of load point ECOST using sector CDF

The total expected cost is 115.045 k$/yr which is a decrease of 57.48% from the ECOST value calculated in Case 3 and is closer in value to Case 2. The differences between these two values obtained using system CCDF and sector CDF is shown graphically by comparing the load point ECOST values in Fig 4.3

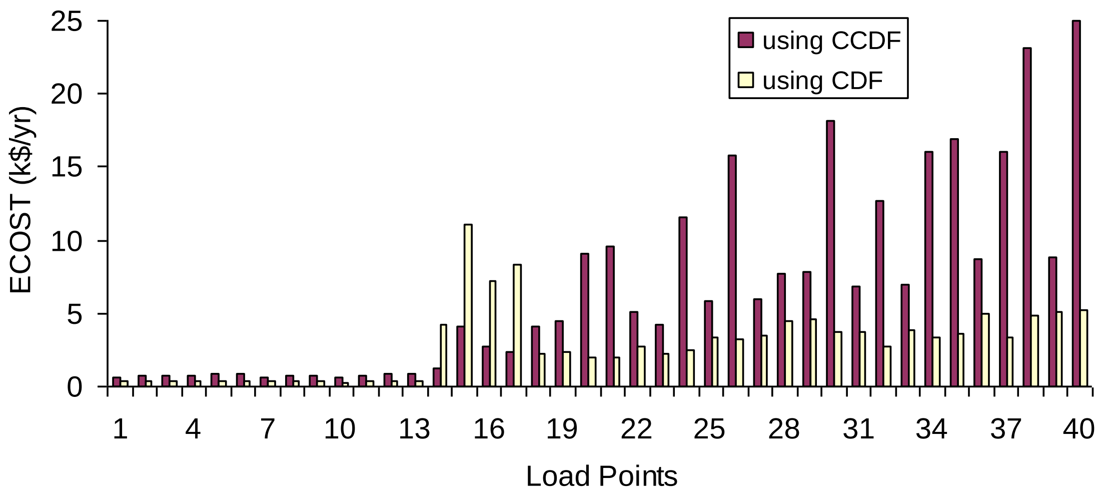


Fig. 4.3 Comparison of load point ECOST calculated using system CCDF and sector CDF

Fig. 4.3 shows that the type of customer at the load points and the proportion of the sectors in the system need to be considered when applying the system CCDF to calculate the expected cost. The customers at load points whose sector CDF are much higher than the rest of the sectors will have lower load point ECOST values while the rest might have a higher load point ECOST when the system CCDF is used. This is due to the assumption of proportional distribution of all load curtailments across all sectors while aggregating the sector CDFs to create the system CCDF.

The use of system CCDF shows a decrease in the load point ECOST values across Feeder 3, i.e. load points 14 to 17, since this sector has a relatively very high sector CDF compared to the rest of the sectors. In contrast, the rest of the load points experienced an increase in their load point ECOST values. Some load point ECOST values, such as at load point 40, were up by almost 300% when using the system CCDF compared with the use of sector CDF.

**Case 5: Variation using Feeder CCDF**

The total expected cost at the bus can be calculated using the mix of customers at load points in that bus. Table 2.5 in Chapter 2 shows the Feeder CCDF at Bus 6 of the RBTS. In Feeder 3 of Bus 6, there is a 35.8% commercial and 64.2% industrial customer composition at peak load. Table 4.3 lists the CCDF for Feeder 3.

Table 4.3 CCDF for Feeder 3

| Duration | $/kW |
|---|---|
| 1 min | 1.1796 |
| 20min | 3.5462 |
| 1 hr | 8.8942 |
| 4 hr | 27.3661 |
| 8 hr | 65.5456 |

The total expected cost at Feeder 3 is calculated to be 30.9524 k$/yr compared to the expected cost of 30.8521 k$/yr at that feeder obtained from Case 4 above. Understanding the type of customers at any load point and feeder can provide a very accurate value of ECOST at that point. To illustrate this, the comparison of the expected costs at load points using the Feeder CCDF and using sector CDF, as in Case 4, for Feeder 3 is shown in Fig. 4.4.

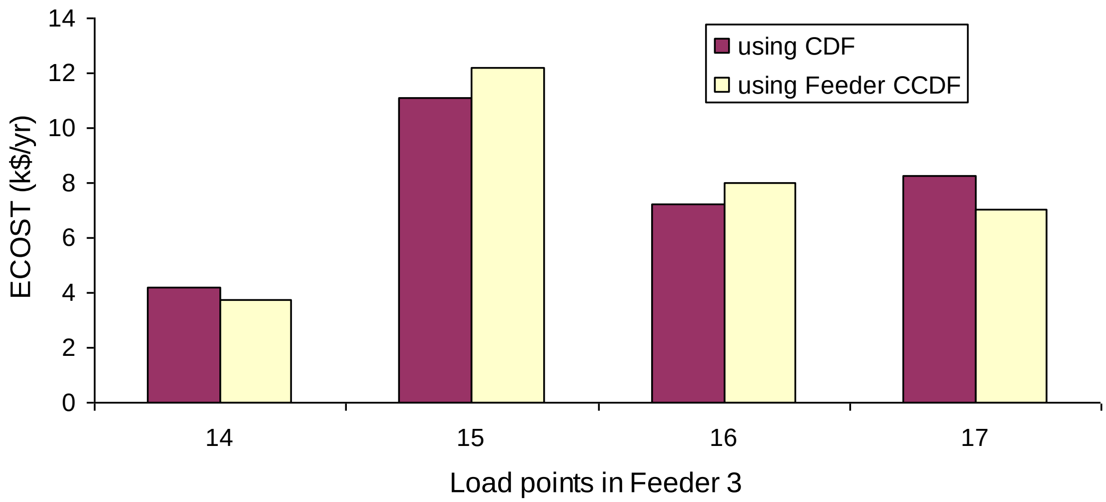


Fig. 4.4 Comparison of ECOST obtained using sector CDF and Feeder CCDF

**4.3 Time Sequential Monte Carlo Simulation Technique**

**Case 6: Repair duration and system CCDF**

In this case, the fixed mean repair duration of a component is considered and the customer interruption costs are obtained using the system CCDF. The mean repair time of both the main sections and lateral sections is 5.0 hours and the replacement time of a transformer is 10.0 hours. The switching time is 1.0 hour. Fig. 4.5 shows the comparison between this case and Case 3 to illustrate the similarity in the load point costs and total expected costs thus obtained.

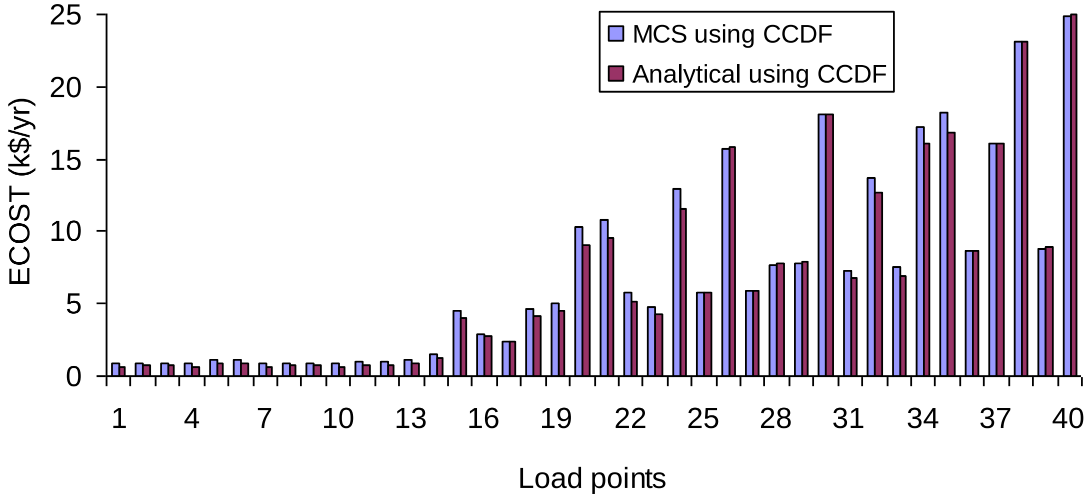


Fig. 4.5 Comparison between Monte Carlo and Analytical techniques using the system CCDF

The slight discrepancy in the load point ECOST values in these two different cases is due to the randomness involved in the Monte Carlo simulation technique. The total expected cost thus obtained using Monte Carlo simulation technique is 284.7278 k$/yr and is an increase of only 5.22% from that of Case 3.

**Case 7: Repair duration and sector CDF**

This technique for calculating load point ECOST and total expected cost is similar to that in Case 6. The difference is the use of sector CDF to obtain the customer interruption costs. The total ECOST obtained in this case is 121.3199 k$/yr and is an increase of 5.5% from the ECOST obtained using the analytical technique in Case 4. It is however, a decrease of almost 57.4% from the total expected cost obtained in Case 6 where system CCDF is used.

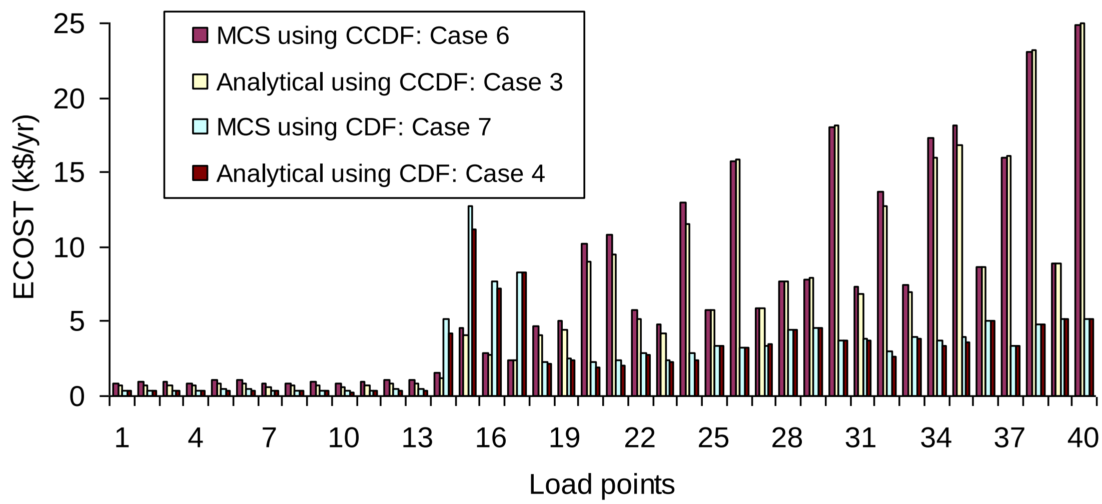


Fig. 4.6: Comparison of Monte Carlo and Analytical techniques using CCDF and CDF

The load point ECOST and total expected cost calculated using the simulation technique with average repair duration are very close to the values obtained with the analytical technique when either the system CCDF or sector CDF is used in both cases. The use of the system CCDF exaggerates the expected cost at load points whose sector CDF is much lower than the other sectors. This effect is reversed for load points whose sector CDF is much higher than the rest of the sectors.

Hence, in practical studies, use of sector CDF provides a more accurate ECOST results whether analytical or Monte Carlo simulation techniques are applied.

**Case 8: Repair duration distribution and sector CDF**

In this technique, various repair duration distributions are considered and the load point cost and the total expected cost are evaluated using the customer interruption cost obtained from the sector CDF data. Four different distributions – hyper-exponential, exponential, Rayleigh and normal distributions – with their mean equal to the average repair duration are considered.

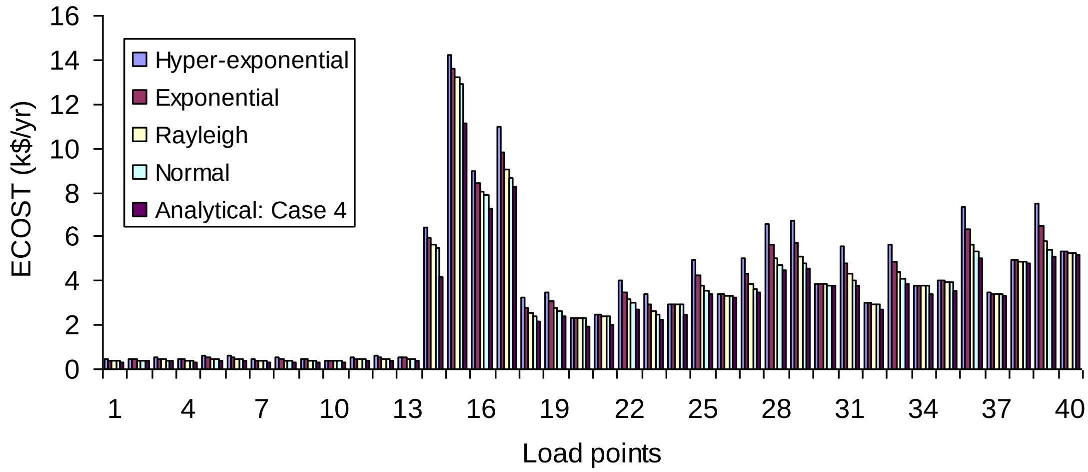


Fig. 4.7: Consideration of repair duration distributions in load point ECOST values

It can be seen from Fig. 4.7 that the load point expected cost values tend to move towards the analytical values as the repair duration distributions vary from hyper-exponential to normal distributions respectively.

Table 4.4 Variation in system ECOST due to repair duration distributions

| | Repair Duration Distribution | | | |
|---|---|---|---|---|
| | Hyper-exponential | Exponential | Rayleigh | Normal |
| Total ECOST (k$/yr) | 150.3606 | 137.8384 | 129.5189 | 125.3414 |

Table 4.4 shows that the total ECOST increases as the repair duration distribution is changed from normal to hyper-exponential distributions. The total ECOST can be compared with the value of 115.045 k$/yr obtained in Case 4 using the analytical technique. Hyper-exponential repair duration distributions resulted in increases of about 30% while normal repair duration distributions showed increases of 9% compared to the total ECOST calculated in Case 4. The expected load point costs also increased significantly in some cases. These results are further analyzed in Chapter 5.

### 4.4 Summary

This chapter analyzes various different techniques to evaluate the expected cost at the load points and the system. Each of these techniques varies from the simplest analytical approach to the more complex approach using Monte Carlo time sequential simulation techniques in the evaluation of ECOST. The information required of the system and failure events and the interruption costs also increases with the complexity of these evaluation techniques. The collection of the additional data may result in higher investment and operational costs for the utilities. The variation in the expected cost value using these different techniques may be used in determining the level of accuracy the utility may want and hence invest in the system.

The simplest analytical technique, Case 1, uses the SAIFI and the equivalent interruption cost from the system CCDF for the system CAIDI to evaluate the total expected cost. This technique resulted in the system ECOST of 176.2 k$/yr. The modified version of this technique, Case 2, used the SAIFI and CAIDI information from the main feeder level and the feeder CCDF to evaluate the expected cost at the feeder and system level. The total expected cost was 99.7 k$/yr. This is a decrease of 43.4% from that obtained using the simplest technique.

The system CCDF and the detailed analytical technique were used in Case 3 to evaluate the expected cost at the load point and system levels. The total expected cost evaluated for the system was 270.6 k$/yr. This is an increase of 171.4% from Case 2 and an increase of 53.6% from Case 1.

The load point ECOST is affected by the peak load and the operative layout of the system to that load point. A composite customer damage function assumes the proportional distribution of all load curtailment. Hence, with information of interruption costs of different sectors of customers at different load points, the variation of load point expected costs can be analyzed as in Case 4. The total expected cost is 115.1 k$/yr, which is a decrease of 57.5% from the ECOST value calculated in Case 3. The customers at load points whose sector CDF is much higher than the rest of the sectors had lower load point expected costs while the rest may have higher expected costs with use of the system CCDF. At load point 40, using the system CCDF resulted in a 300%

higher expected cost compared with the use of the sector CDF. Thus, the influence of use of the system CCDF is very prominent in calculating the expected costs. The type of customers at the load points need to be carefully examined when applying the system CCDF.

The customers at load points considered so far were all homogenous in nature. However, a mixture of various customer sectors may exist at a load point. This case is analyzed by selecting Feeder 3 with a mixture of 35.8% commercial and 64.2% industrial customers. The application of the resultant feeder CCDF using the information from the respective sector CDFs resulted in an expected cost of 30.9 k$/yr. This was an increase of only 0.3% from the value calculated in Case 4. Therefore, understanding the type of customers at any load point and feeder can provide a very accurate value of ECOST at that point..

The Monte Carlo simulation technique is applied in Cases 6 and 7. Fixed repair duration along with system CCDF and sector CDF are applied respectively in these cases resulting in ECOST values of 284.7 k$/yr and 121.3 k$/yr, which is an increase of 5.2% and 5.5% compared to results using analytical approaches with system CCDF and sector CDF in Cases 3 and 4. Hence, the use of Monte Carlo simulation technique is not particularly beneficial in this case. The utilization of system CCDF will always result in higher expected cost values than the use of sector CDF whether the technique used is analytical or simulation in nature.

Case 8 involved applying repair duration distributions in the Monte Carlo simulation technique. Interruption costs were obtained from the sector CDF data. The result is an increase of 30% to 9% to the analytical technique in Case 4 depending upon the type of repair duration distribution used. A hyper-exponential repair duration distribution resulted in the total ECOST of 150.4 k$/yr – a 30% increase. The difference in the total ECOST decreased with the increase in the shape parameter values used for the repair duration distribution.

# CHAPTER 5

# EFFECT OF REPAIR DURATION DISTRIBUTIONS ON EXPECTED COST AND RELIABILITY INDICES

## 5.1 Introduction

The Monte Carlo time sequential simulation technique was used to study the effect of using repair duration distributions with the average repair duration as their mean. By changing the shape parameter in the Weibull distribution, various important distributions can be obtained and the resulting variation in expected customer costs (ECOST) can be analyzed. All components were assumed to follow the same repair duration distribution. Distributions resembling hyper-exponential, exponential, Rayleigh and normal distributions were studied. The load point expected costs and total ECOST were then evaluated using the simulation technique. The respective sector customer damage function (CDF) was used for these calculations unless otherwise stated.

## 5.2 Effect on ECOST

The customer interruption costs are directly related to the outage duration. Hence, the expected customer costs will vary with variations in the repair duration distributions. The variance around the mean of the customer costs can provide the distribution planner with information on the risk associated in terms of costs.

### 5.2.1 Variation in ECOST

The variation in the total expected cost when different repair duration distributions are applied is shown in Table 4.4. A comparison is made with the ECOST calculated using the analytical technique in Case 4 in Chapter 4. This is illustrated pictorially in Fig. 5.1 which shows a tendency for ECOST to move closer to the value obtained using the analytical technique as the Weibull shape factor increases.

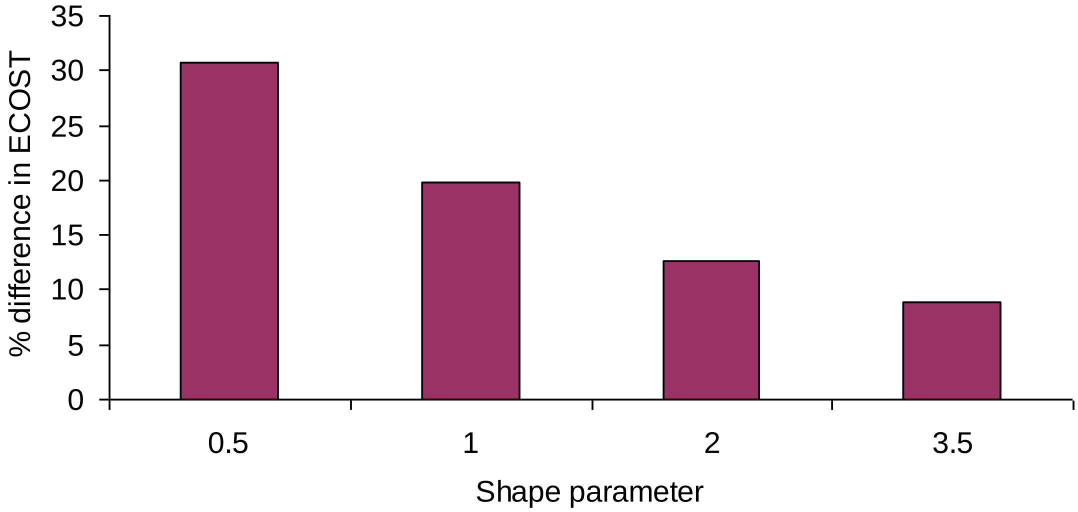


Fig. 5.1 Percentage difference in total ECOST at various shape parameter values compared with the analytical calculation

The total expected system outage cost is about 30% higher when the hyper-exponential distribution (shape parameter=0.5) is selected as the repair duration distribution and is about 9% higher when an approximate normal distribution (shape parameter=3.5) is selected. The applied repair duration distribution affects the total ECOST to varying degrees.

The effect of applying repair duration distribution on the expected cost at the load points was also analyzed. To better appreciate the variation, the percentage difference in the costs at load points compared to the analytical calculation of load point expected cost is graphically shown in Fig. 5.2.

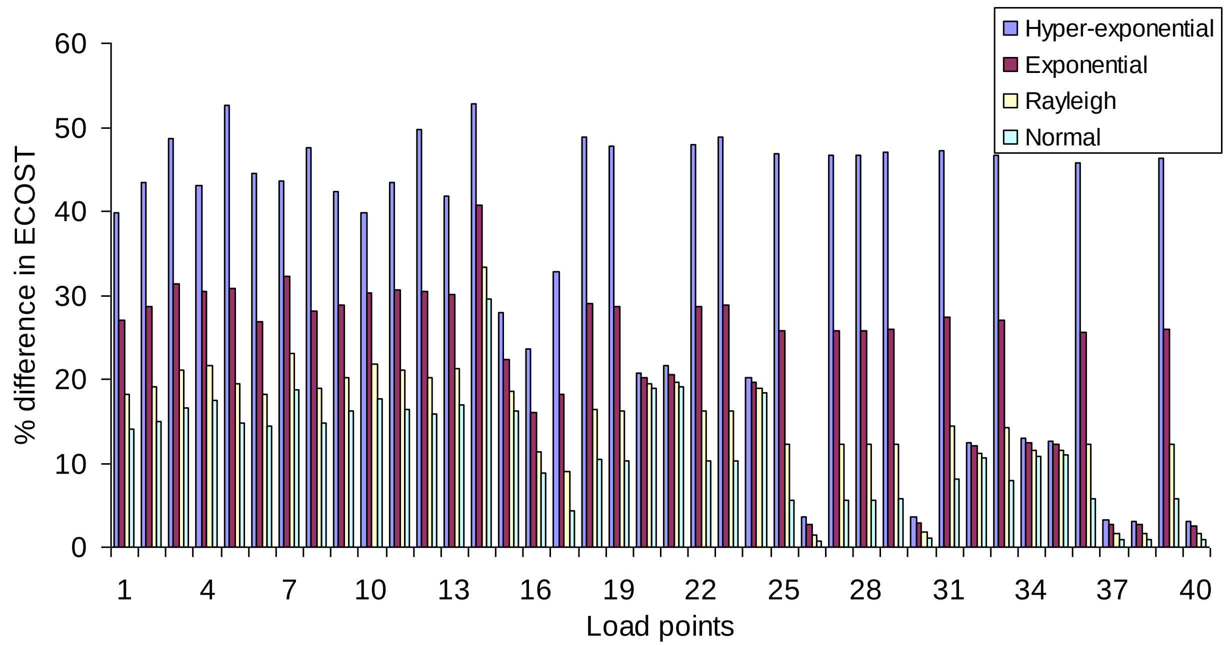


Fig. 5.2 Percentage difference in load point ECOST at using sector CDF compared with the analytical calculation

The variation in the load point expected costs is even greater than the variation in total ECOST. The use of hyper-exponential distributions tends to produce a bigger percentage difference in the load point ECOST across all load points. The difference varies from 52% to 3% in this case. Again, the application of the normal distribution of the repair durations resulted in the least difference in the load point ECOST from 30% to 1% compared with the results of the analytical technique in Case 4 shown in Chapter 4.

The use of different distributions for repair duration also shows an increase in expected cost at load points with certain customer sectors. The variation is large for Residential customers and is the least for Agricultural customers irrespective of the type of distribution selected for the repair duration. The application of hyper-exponential distributions resulted in the largest difference in the load point ECOST while normal distributions resulted in the least difference. The slope of the sector CDF for agricultural customers is the lowest while it is the highest for residential customers as shown in Fig. 2.7. This indicates that the sector CDF data play an important role when repair duration distributions are used to calculate the expected costs.

The variation in the load point expected costs due to the application of different repair duration distributions can be better analyzed in terms of the layout of the system using the system CCDF. Fig. 5.3 shows the percentage difference in load point expected costs compared with the analytical calculation using the system CCDF.

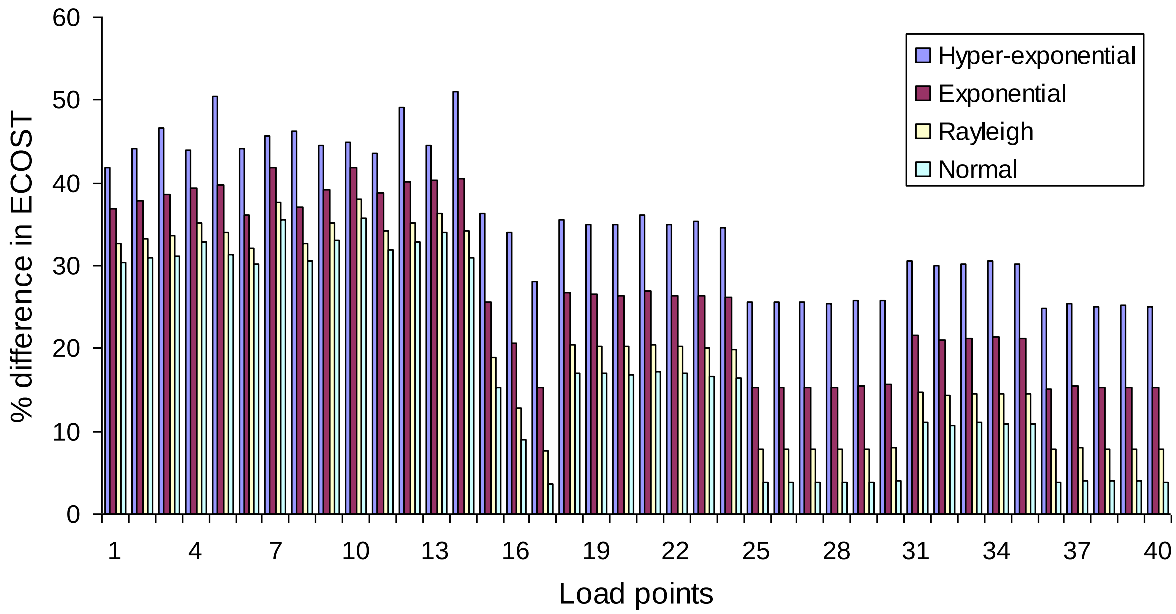


Fig. 5.3 Percentage difference in load point ECOST using system CCDF compared with analytical calculation

The variation in expected costs is more uniform across all the load points using the system CCDF. Application of hyper-exponential distributions for repair duration resulted in percentage differences of 51% to 25% while the use of the normal distributions gave differences of 35% to 4% across the load points.

It is seen from Fig. 5.3 that the operational layout of the system also determines the variation in the expected costs with relation to different repair duration distributions. Feeders 1 and 2 consisting of load points 1 to 13 contains alternate supply and disconnects. Hence, even though the differences in the expected costs at these load points are large compared to the analytical calculation of load point expected costs using the system CCDF (Case 3), the variation in ECOST with respect to each other is quite uniform.

On the other hand, the load points 25 to 30 and 36 to 40 have the highest difference in load point expected costs with respect to the applied repair duration distributions. These load points are the most unreliable since they are at the end of a long feeder without any alternate supply. When the normal distribution is selected, the difference is at its least at these load points when compared with the respective analytical values. Feeder 3 does not contain any alternate supply but has disconnects between each load point. Load point 14 in Feeder 3 shows the biggest percentage difference in expected cost for all four repair duration distributions compared to the respective analytical value while load point 17 shows the least percentage change. The difference in load point expected costs between different repair duration distributions is at the least at load point 14 and is at the greatest at load point 17.

The application of various repair duration distributions enhances the impact of the peak load, system layout and sector CDF data on the load point expected costs and ultimately, in the total system ECOST. Nevertheless, increase in the shape parameter for the type of repair distribution decreases the difference in the total expected cost.

### 5.2.2 Effect of linear extrapolation of sector CDF

The sector customer damage function is created using information from surveys. However, due to the limitation of such a technique, only a certain amount of data can be obtained. Linear extrapolation has been applied to obtain the interruption cost beyond the maximum duration point in the sector CDF as noted in (2.13). This has been applied in all the cases listed above.

The effect on load point expected costs without application of linear extrapolation of sector CDF was also analyzed for different repair duration distributions. This means that the sector interruption cost for any outage duration greater than the largest outage duration for which the interruption cost can be obtained from Table 2.1 will remain the same. The interruption cost is not increased beyond the values in Table 2.1 even if the outage durations are longer. The variation in the ECOST thus obtained compared to the analytically calculated values without linear extrapolation is show in Fig. 5.4.

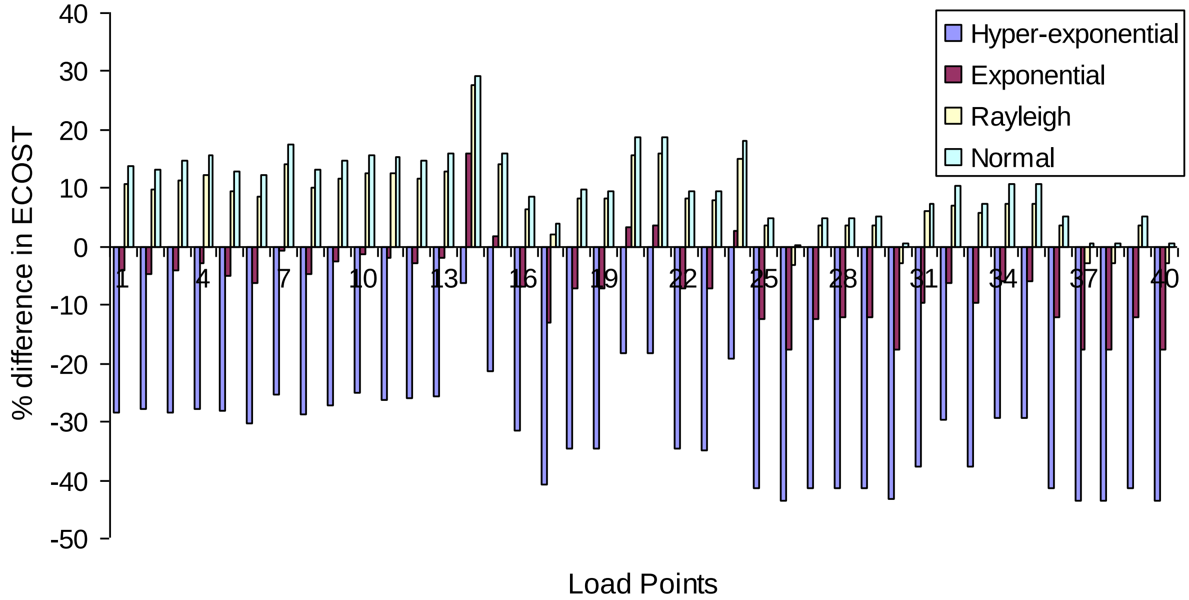


Fig. 5.4 Percentage difference in load point ECOST without linear extrapolation of sector CDF

Due to the nature of the hyper-exponential distribution, removing the linear extrapolation affects it the most. Certain load point ECOST decreased by almost 45%. The effect of sector CDF linear extrapolation is less for the Rayleigh distribution and minimum for a normal repair duration distribution in terms of the load point ECOST as shown in Figures 5.5 and 5.6 respectively.

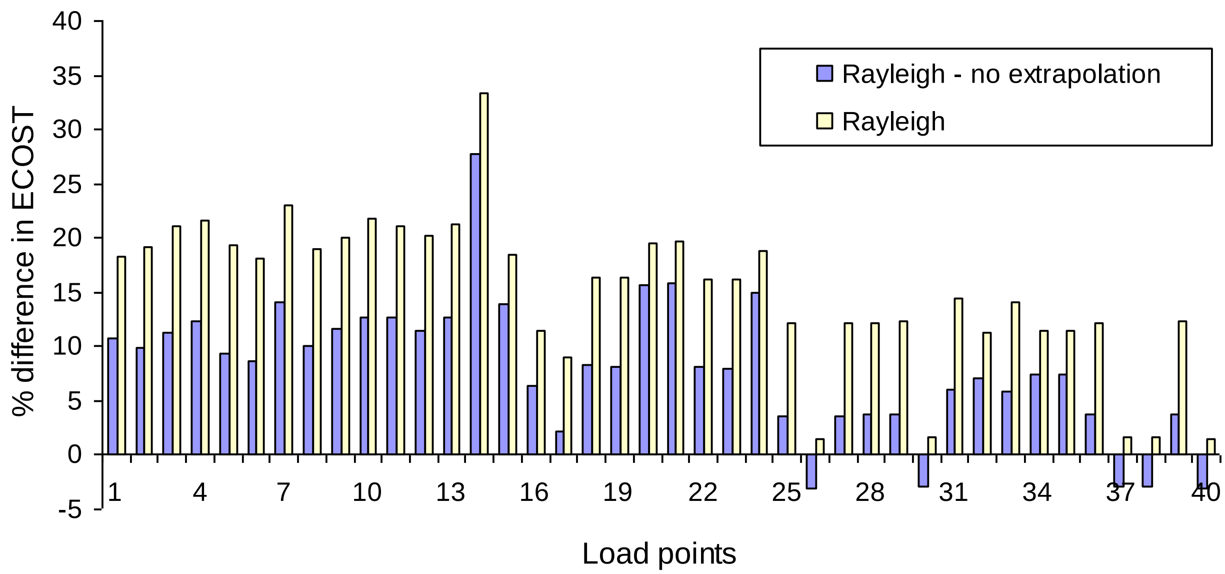


Fig. 5.5 Effect of linear extrapolation of sector CDF with Rayleigh repair duration distribution

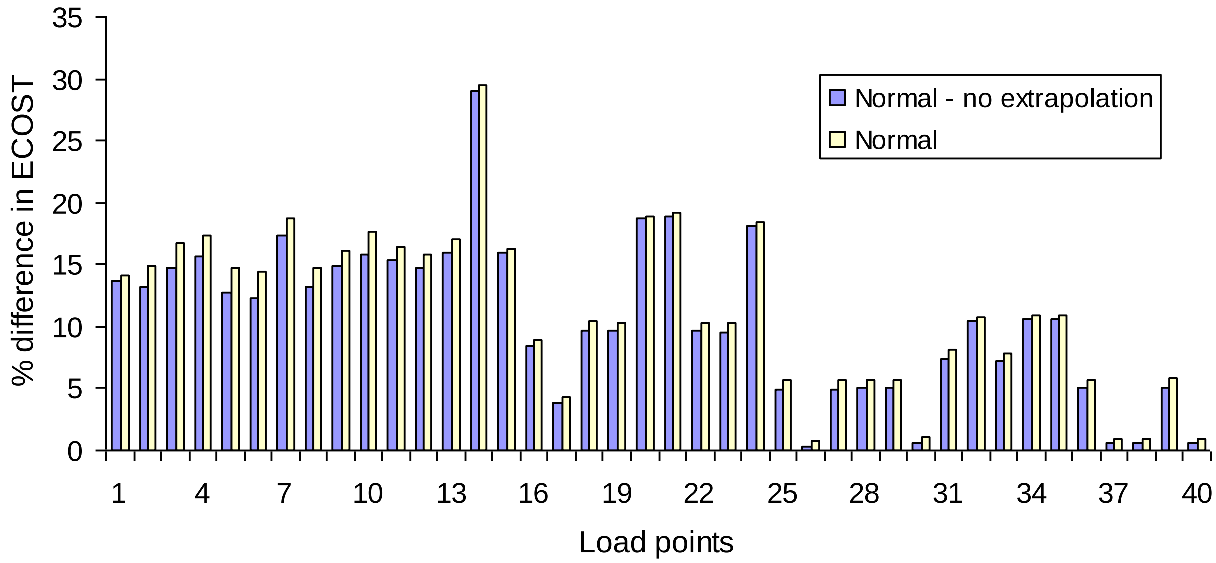


Fig. 5.6 Effect of linear extrapolation of sector CDF with Normal repair duration distribution

The load point expected costs are least affected without linear extrapolation of sector CDF when a normal repair duration distribution is applied. The hyper-exponential distribution depends heavily on the assumption used for linear extrapolation and this is reflected on the load point and system expected costs.

**5.3 Effect on Reliability Indices**

The effect of repair duration distributions on the customer and load oriented indices were studied using a Weibull distribution for the repair duration and changing the shape parameter, β. The switching time was modeled with deterministic durations.

The SAIDI, SAIFI, CAIDI, IOR, CEMI and CELID customer-based indices and the ASIFI and ASIDI load-based indices, which are described in Chapter 2, were considered to see the effect of repair duration distributions.

### 5.3.1 Customer-Oriented Indices

#### SAIDI – System Average Interruption Duration Index

The distributions of SAIDI at the feeder level and system level followed the selected repair duration distributions. Table 5.1 lists the mean and standard deviation (S.D) for the SAIDI distribution at the feeder and system level obtained with respect to the changes in the shape parameter of the repair duration distribution.

Table 5.1 Changes in mean and standard deviation of SAIDI (hr/cust.) for various feeders and the system with respect to changes in β

| | Feeder 1 | | Feeder 2 | | Feeder 3 | | Feeder 4 | | System | |
|---|---|---|---|---|---|---|---|---|---|---|
| β | *Mean* | *S.D.* | *Mean* | *S.D.* | *Mean* | *S.D.* | *Mean* | *S.D.* | *Mean* | *S.D.* |
| 0.5 | 0.8438 | 2.1201 | 0.8653 | 1.9213 | 0.8878 | 4.1934 | 8.2373 | 12.9293 | 3.8283 | 5.2704 |
| 1 | 0.8379 | 1.3753 | 0.8669 | 1.2935 | 0.8716 | 2.3516 | 8.2323 | 7.5132 | 3.8251 | 3.0749 |
| 2 | 0.8368 | 1.1876 | 0.8664 | 1.1327 | 0.8698 | 1.8995 | 8.2347 | 6.0589 | 3.8256 | 2.4873 |
| 3.5 | 0.8366 | 1.1387 | 0.8659 | 1.0898 | 0.8696 | 1.7798 | 8.2346 | 5.6596 | 3.8254 | 2.3264 |

The standard deviation of SAIDI decreases with the increase in β resulting in the distribution that starts to resemble the interruption duration distribution itself. The SAIDI is a function of both the frequency and duration of load point failure. Hence, the increase in repair duration will result in an increase in SAIDI. Fig 5.7 provides a pictorial representation of SAIDI for Feeder 1 of Bus 6 when $\beta = 2$. In this case, there is a high probability of a zero value for SAIDI. This is due to the presence of disconnects on the feeders and the normally open disconnect between Feeders 1 and 2. When the rest of the distribution of SAIDI is considered as shown in Fig 5.8, it resembles a Rayleigh distribution like the repair duration distribution itself. Fig 5.9 illustrates the impact on SAIDI without the presence of disconnect between the two feeders. The probability of SAIDI for Feeder 1 having higher values thus increases when the back feed is removed.

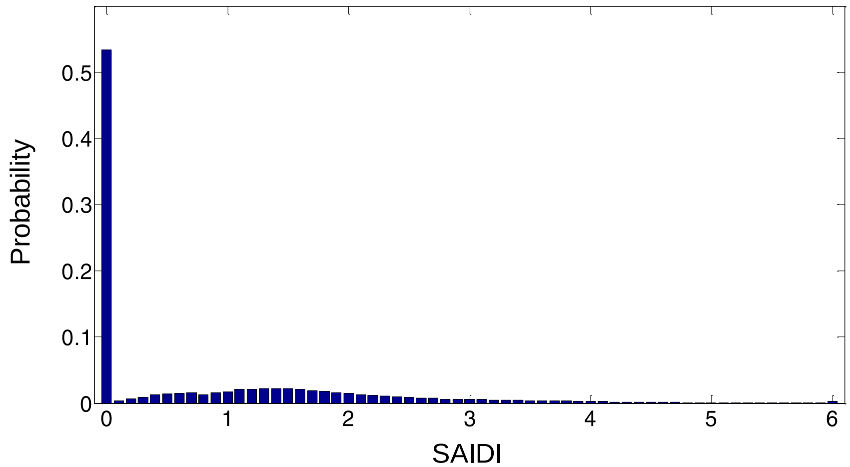

Fig. 5.7 Distribution of SAIDI for Feeder 1 when β = 2

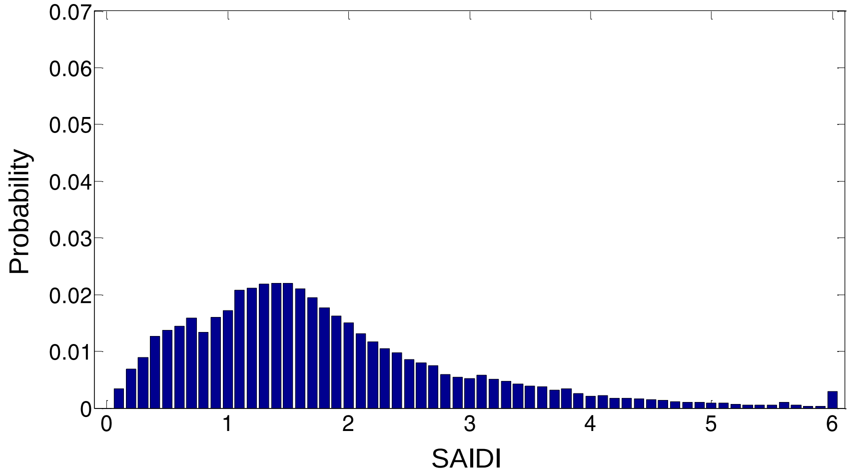

Fig. 5.8 Distribution of SAIDI>0 for Feeder 1 when β = 2

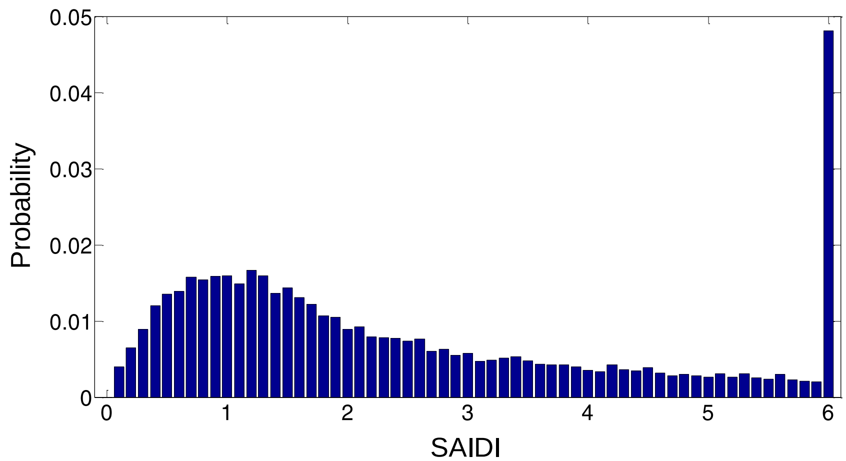

Fig. 5.9 Distribution of SAIDI>0 for Feeder 1, without back feed, when β = 2

Figures 5.10 to 5.13 show the effect of repair duration distribution, with various shape parameter factors, on the SAIDI distribution at the system level. The distribution of SAIDI closely follows that of the repair duration distribution itself. The increase in standard deviation of the repair duration distribution applied results in a similar increase in the standard deviation of the respective SAIDI distribution. Fig 5.14 shows the effect on SAIDI using fixed repair durations of 5.0 hours for both main and lateral sections and replacement time of 10.0 hours for a transformer. The switching time of the disconnect is 1.0 hour. This results in SAIDI with a distribution similar to that in Fig. 5.13.

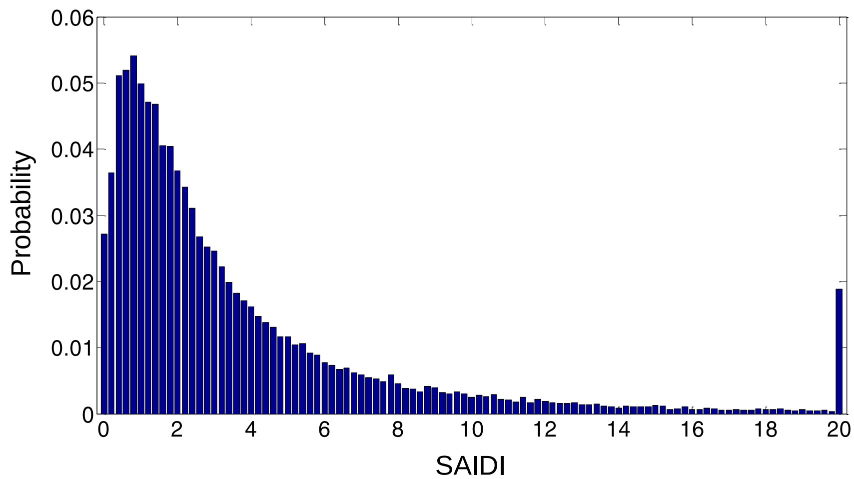

Fig. 5.10 Distribution of SAIDI for the system when β = 0.5

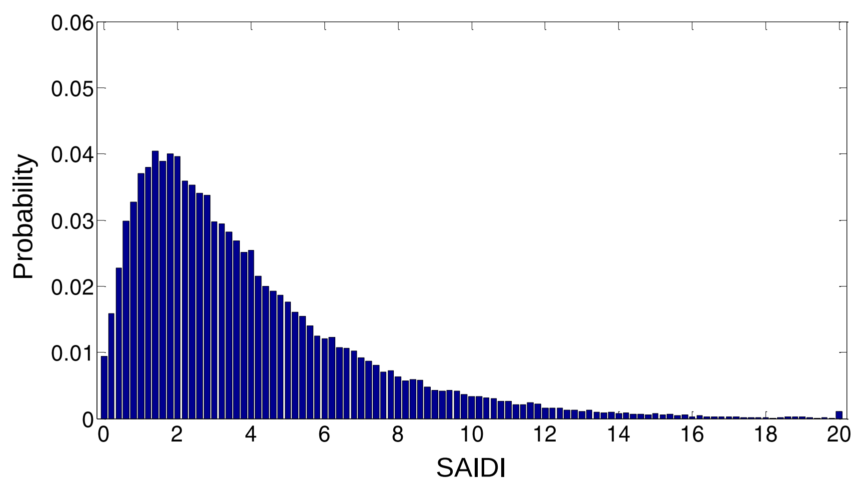

Fig. 5.11 Distribution of SAIDI for the system when β = 1

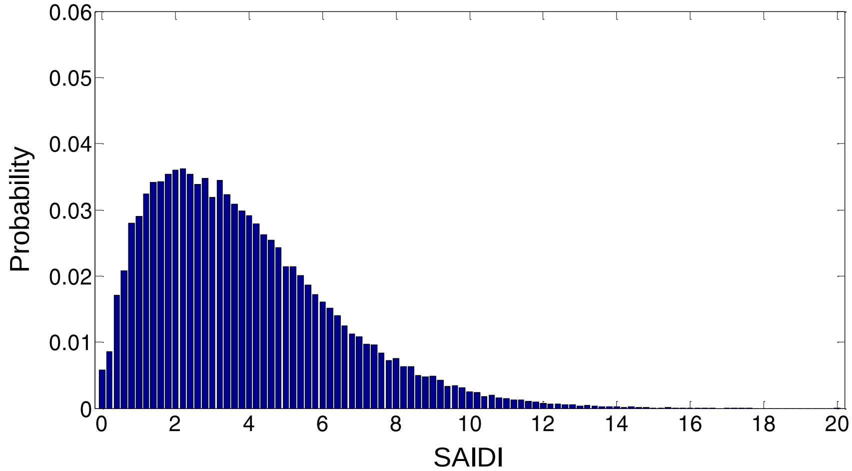


Fig. 5.12 Distribution of SAIDI for the system when β = 2

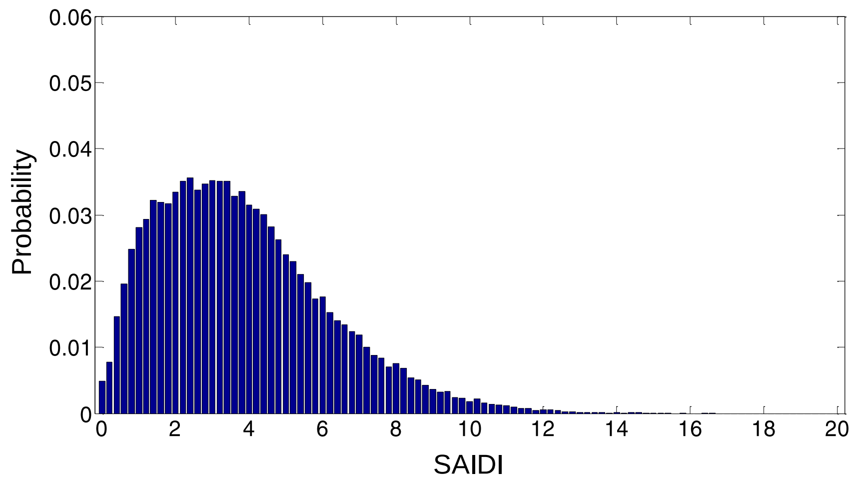


Fig. 5.13 Distribution of SAIDI for the system when β = 3.5

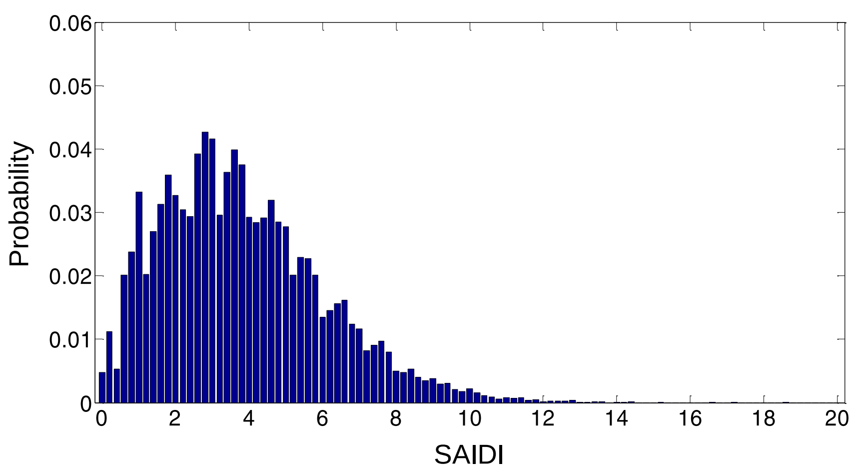


Fig. 5.14 Distribution of SAIDI for the system using fixed repair durations

**SAIFI – System Average Interruption Frequency Index**

The SAIFI depends primarily on the frequency of failures and hence there is no significant effect of varying the repair duration distributions on it. It is also a function of the topology of the system and the equipment parameters. Fig. 5.15 shows the distribution of SAIFI for the system.

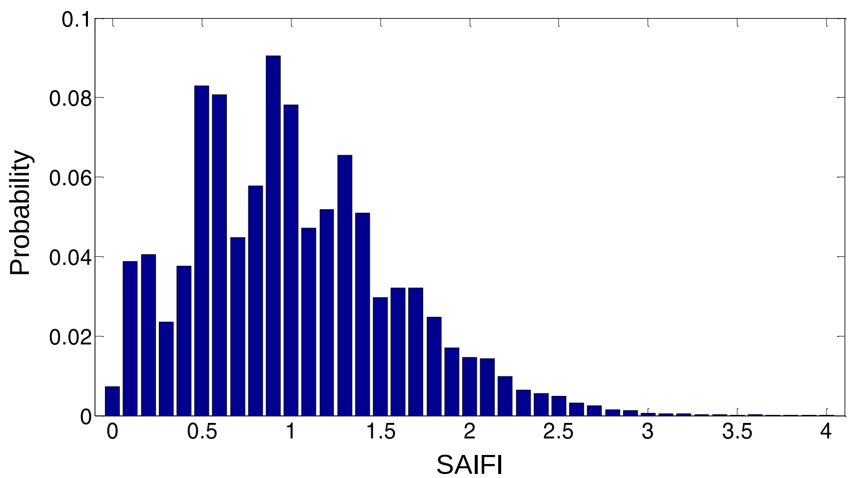


Fig. 5.15 Distribution of SAIFI for the system

Fig 5.16 shows the distribution of SAIFI for Feeder 1. The effect of taking out the alternate supply and doubling the failure rate of all components in Feeder 1 was examined to see if that would make the inclusion of repair duration distributions prominent. Fig. 5.17 shows that the removal of back feed in Feeder 1 resulted in the probability of SAIFI values that are greater than zero to decrease. This is due to the possibility of failures that occur at the top of the feeder lasting longer than the switching time resulting in the rest of the feeder being cut off since the alternate supply has been removed. Hence, the components in the rest of the feeder cannot fail during this time. However, this would also result in longer outage durations for the feeder as shown in the SAIDI values in Fig 5.9. Fig. 5.18 reveals the drop in probability for zero failures and a slight increase in failures across the spectrum due to increasing the failure rate values.

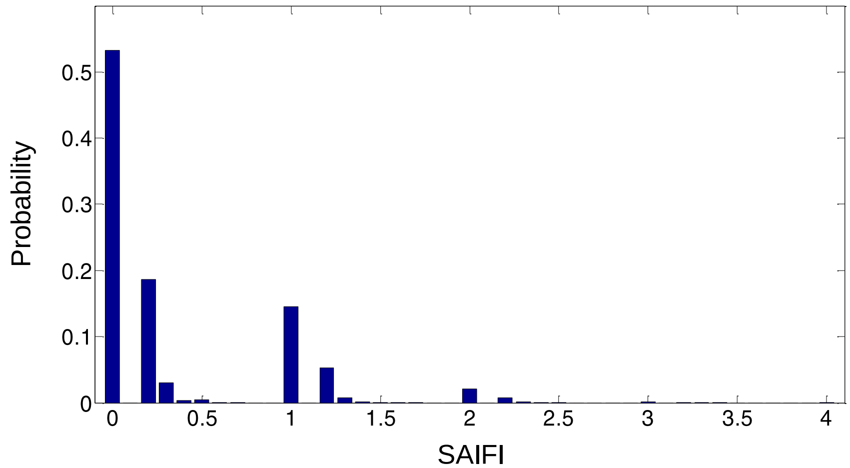


Fig. 5.16 Distribution of SAIFI at Feeder 1

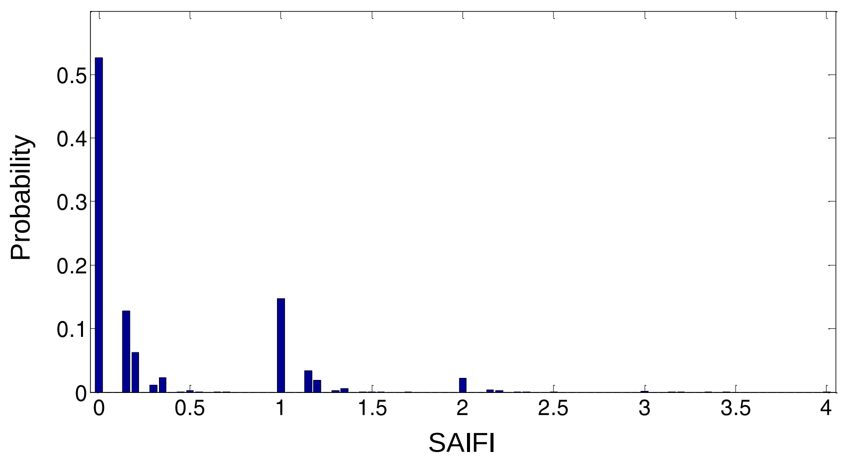


Fig. 5.17 Distribution of SAIFI at Feeder 1 with no back feed

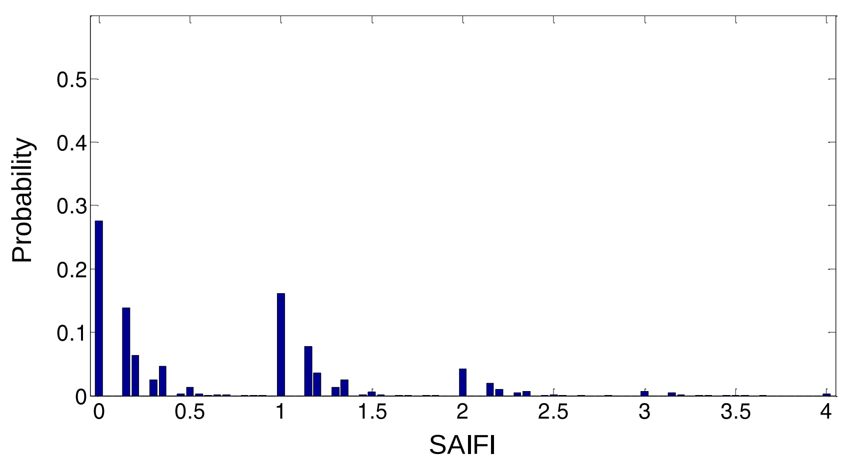


Fig. 5.18 Distribution of SAIFI at Feeder 1 with the failure rate doubled

**CAIDI – Customer Average Interruption Duration Index**

The distribution of CAIDI resembled that of the repair duration distribution. CAIDI is affected not only by the repair duration, but also by frequency of failures. Hence, the CAIDI distribution does not resemble the repair duration distribution as closely as the SAIDI distribution does. Table 5.2 shows the mean and standard deviation of the CAIDI distribution at the feeder and system levels as various repair duration distributions are applied.

Table 5.2 Changes in mean and standard deviation of CAIDI (hr/int) for various feeders and the system with respect to changes in β

| | Feeder 1 | | Feeder 2 | | Feeder 3 | | Feeder 4 | | System | |
|---|---|---|---|---|---|---|---|---|---|---|
| β | *Mean* | *S.D.* | *Mean* | *S.D.* | *Mean* | *S.D.* | *Mean* | *S.D.* | *Mean* | *S.D.* |
| 0.5 | 2.4971 | 9.9214 | 2.3607 | 9.134 | 3.8821 | 8.4062 | 4.1611 | 6.5211 | 3.9290 | 5.0816 |
| 1 | 2.4811 | 5.1475 | 2.3636 | 4.9968 | 3.8104 | 4.0187 | 4.1576 | 3.097 | 3.9504 | 2.5363 |
| 2 | 2.4776 | 3.5023 | 2.3615 | 3.4556 | 3.80193 | 2.2864 | 4.1591 | 1.8122 | 3.9542 | 1.5861 |
| 3.5 | 2.47761 | 2.9736 | 2.3597 | 2.9557 | 3.7998 | 1.5871 | 4.15952 | 1.3324 | 3.9550 | 1.2485 |

Figures 5.19 to 5.23 show the CAIDI distribution for the system with respect to the different shape parameters for repair duration distributions and when fixed repair durations are used.

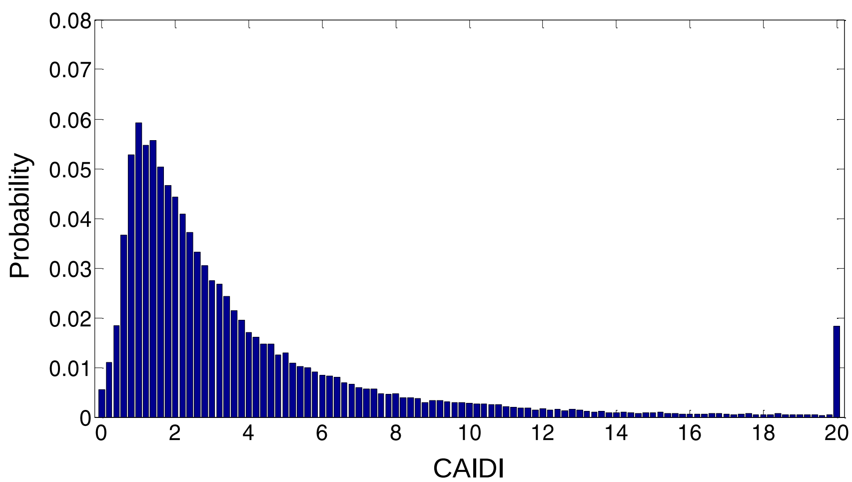


Fig. 5.19 Distribution of CAIDI for the system when β = 0.5

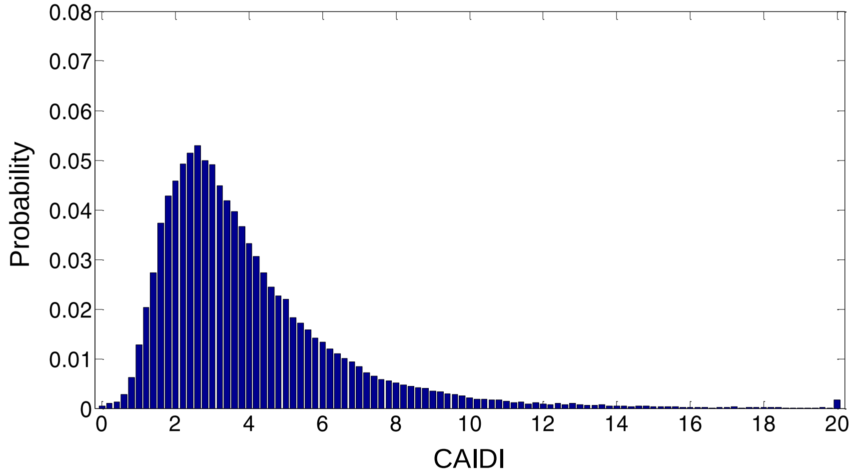

Fig. 5.20 Distribution of CAIDI for the system when β = 1

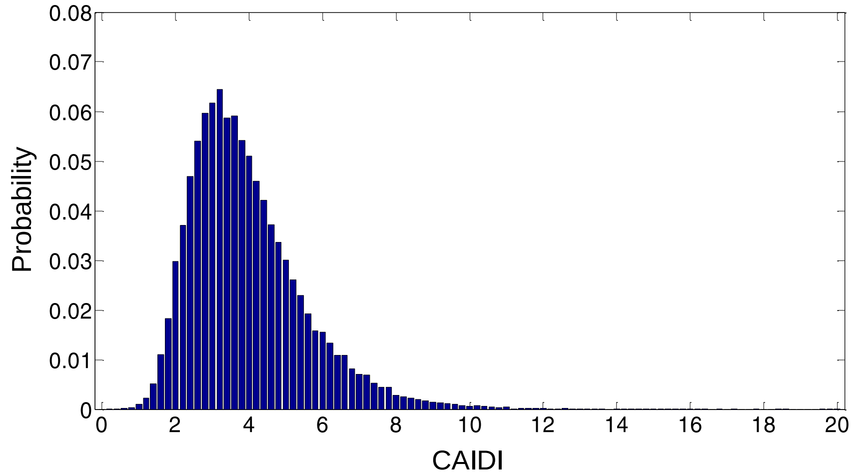

Fig. 5.21 Distribution of CAIDI for the system when β = 2

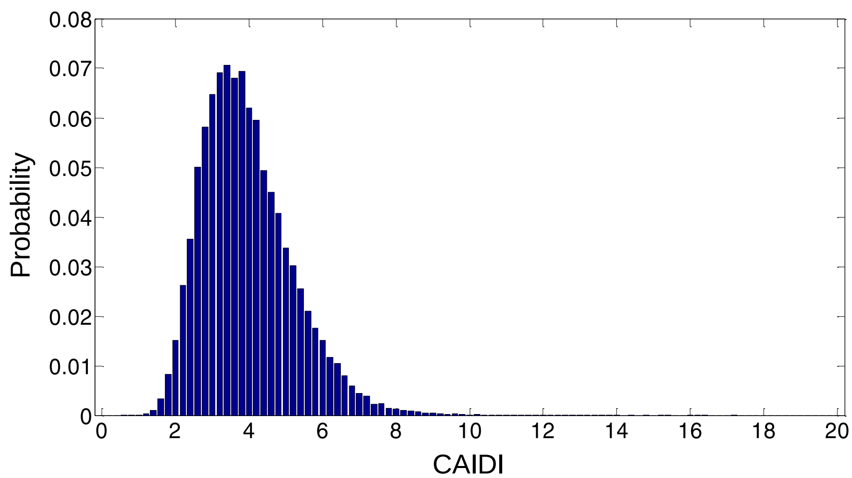

Fig. 5.22 Distribution of CAIDI for the system when β = 3.5

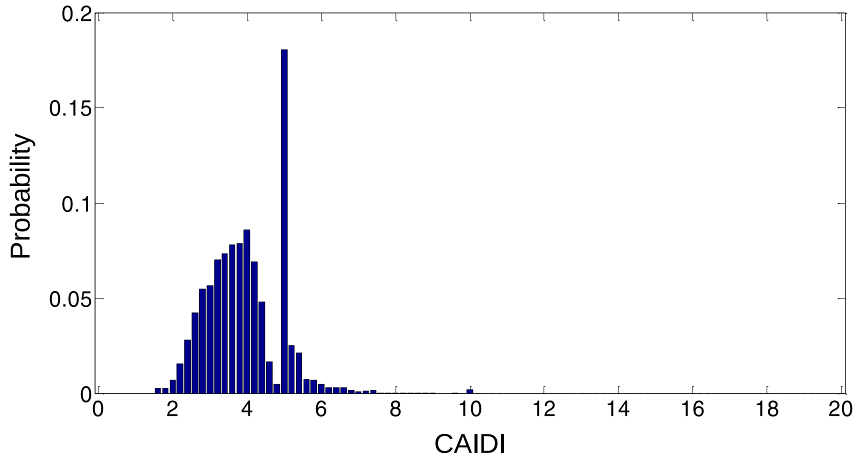

Fig. 5.23 Distribution of CAIDI for the system using fixed repair durations

**IOR – Index of Reliability**

The distribution of IOR was the mirror image of SAIDI as expected. Hence, the repair duration distributions had a significant effect on the IOR distribution. Figures 5.24 to 5.28 show the IOR distribution for the system when different repair duration distributions are applied.

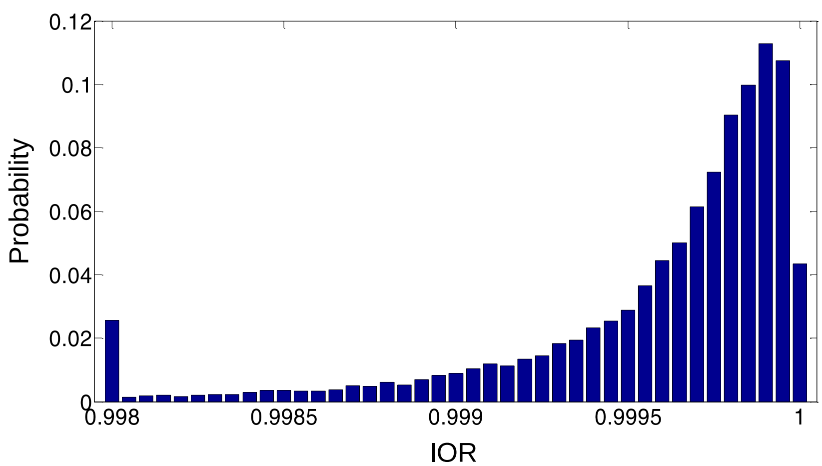

Fig. 5.24 Distribution of IOR for the system when β = 0.5

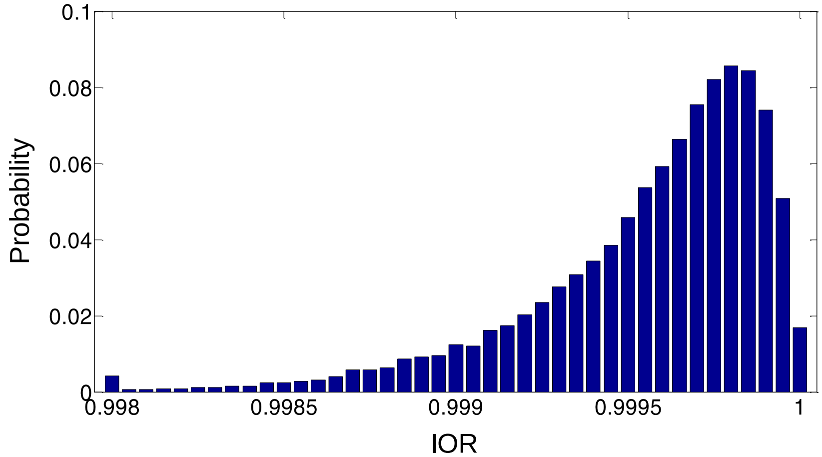


Fig. 5.25 Distribution of IOR for the system when β = 1

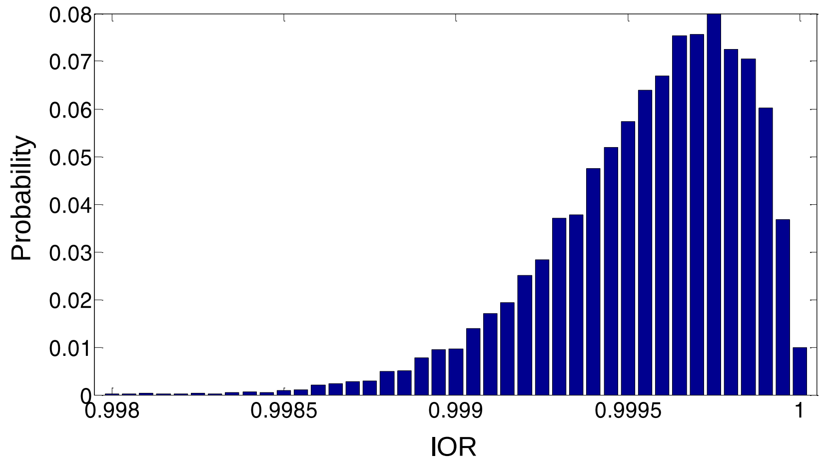


Fig. 5.26 Distribution of IOR for the system when β = 2

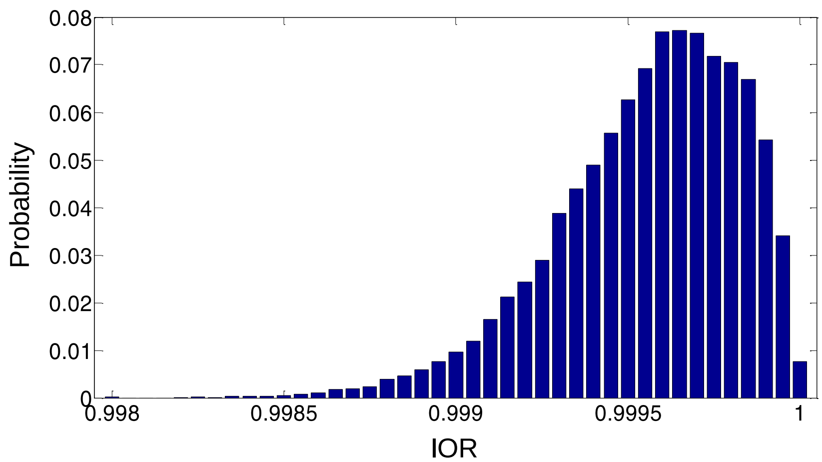


Fig. 5.27 Distribution of IOR for the system when β = 3.5

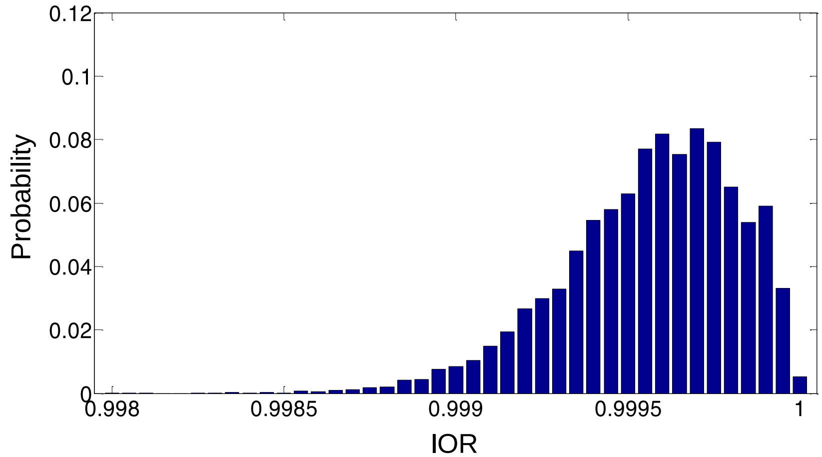

Fig. 5.28 Distribution of IOR for the system using fixed repair duration

**$CEMI_n$ – Customers Experiencing Multiple Interruptions**

This index indicates the percentage of customers interrupted equal to or more than n times per year. The effect on $CEMI_n$ for the system when repair duration distributions are applied is listed in Table 5.3.

Table 5.3 Variation in CEMI-3 for the system using various repair duration distributions

| | Shape Parameter | | | | |
|---|---|---|---|---|---|
| | 0.5 | 1 | 2 | 3.5 | Fixed repair duration |
| $CEMI_n$ (%) n=3 | 13.12 | 13.125 | 13.124 | 13.122 | 12.994 |

The $CEMI_n$ is not affected by the type of repair duration distribution chosen. With n taken to be 3 interruptions, the $CEMI_n$ for the system is 13.12% which reflects that 386 customers faced 3 or more interruptions per year.

**$CELID_n$ – Customers Experiencing Longest Interruption Duration**

This index indicates the percentage of customers experiencing outages equal to or greater than n hours. The number of hours chosen is 5. Table 5.4 lists the $CELID_n$ for the system taking repair duration distributions into consideration.

Table 5.4 Variation in CELID-5 for the system using various repair duration distributions

| | Shape Parameter | | | | |
|---|---|---|---|---|---|
| | 0.5 | 1 | 2 | 3.5 | Fixed repair duration |
| $CELID_n$ (%) n=5 | 16.67 | 25.32 | 31.62 | 34.82 | 68.19 |

It is obvious from Table 5.4 that the repair duration distribution has a direct impact on the $CELID_n$ index. When the repair duration distribution is hyper-exponential, there is less probability that the repair duration will be large. This is reflected by only 16.67% of customers experiencing outages more than 5 hours as shown in the table above. With the increase in the shape parameter, the repair duration distribution has less spread and hence the probability of outage durations more than 5 hours increases as is evident by the increase in $CELID_n$ to 34.8% for repair duration distributions which approximate a normal distribution.

The $CELID_n$ is 68.2% when the average repair duration is used. This sudden increase in the index is due to the 5 hours selected as a criterion. This duration also happens to be the average repair time for the main and lateral section components which dominate the system.

### 5.3.2 Load-Oriented Indices

**ASIFI – Average System Interruption Frequency Index**

This index is similar to SAIFI but using load rather than customers affected. The ASIFI will be the same as the SAIFI in the case of homogeneous distribution of load in the system.

Similar to SAIFI, this index is also not affected by the application of repair duration distributions. Fig. 5.29 shows the ASIFI distribution for the system.

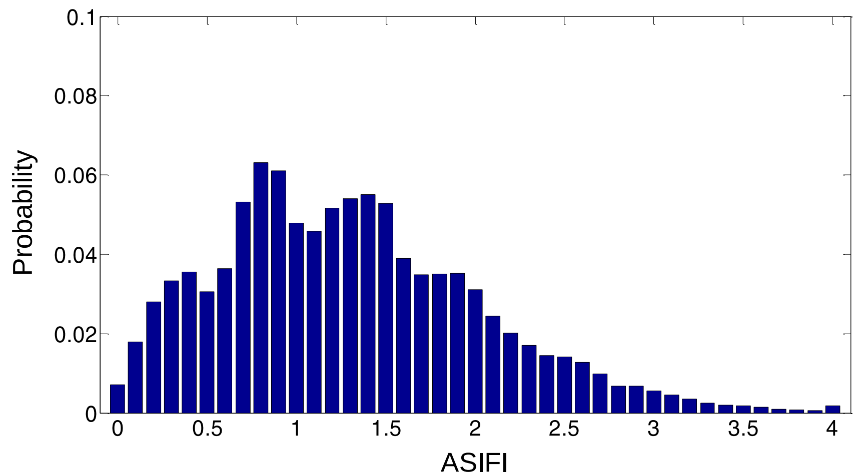


Fig. 5.29 Distribution of ASIFI for the system

**ASIDI – Average System Interruption Duration Index**

ASIDI is a load based index. It is similar to SAIDI but instead of customers, duration of load interrupted is used. The effect of repair duration distribution is felt directly as in the case of SAIDI and the distributions of ASIDI follow the repair duration distributions applied. Figures 5.30 to 5.33 illustrate the distributions of ASIDI with respect to changes in the shape parameter of the repair duration distributions and Fig 5.34 shows the ASIDI when fixed repair durations are used.

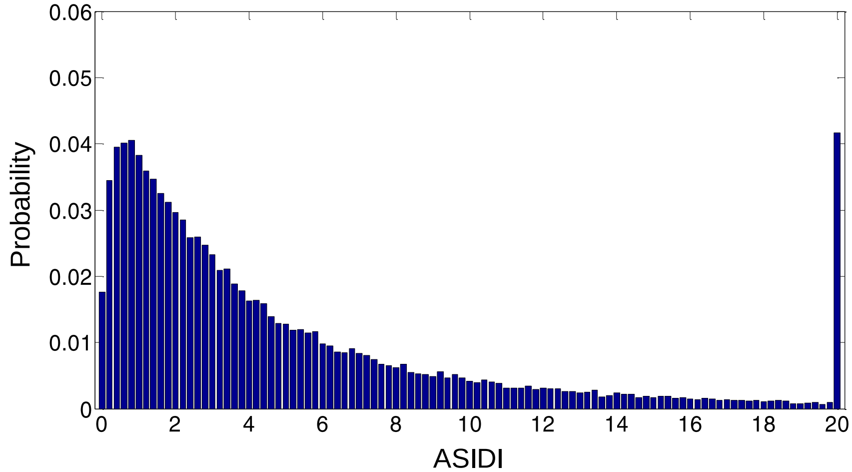

Fig. 5.30 Distribution of ASIDI for the system when β = 0.5

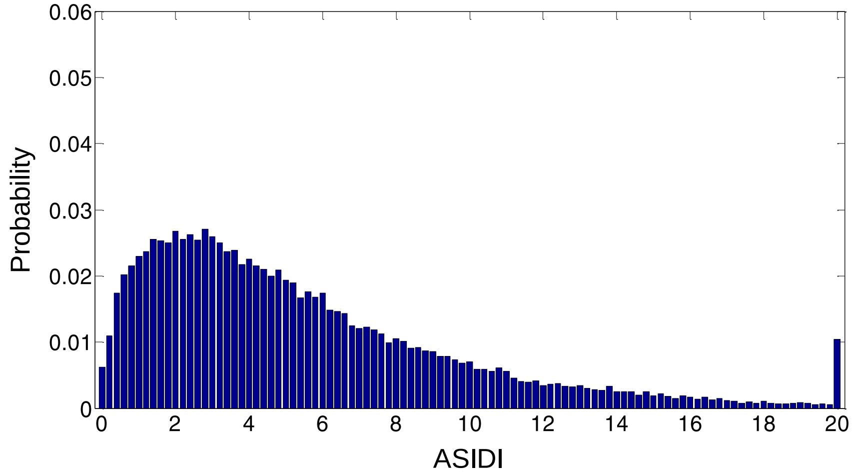

Fig. 5.31 Distribution of ASIDI for the system when β = 1

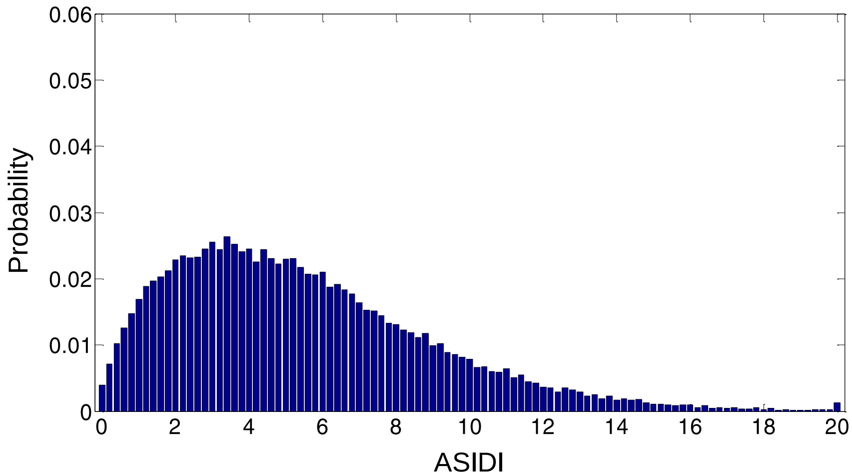

Fig. 5.32 Distribution of ASIDI for the system when β = 2

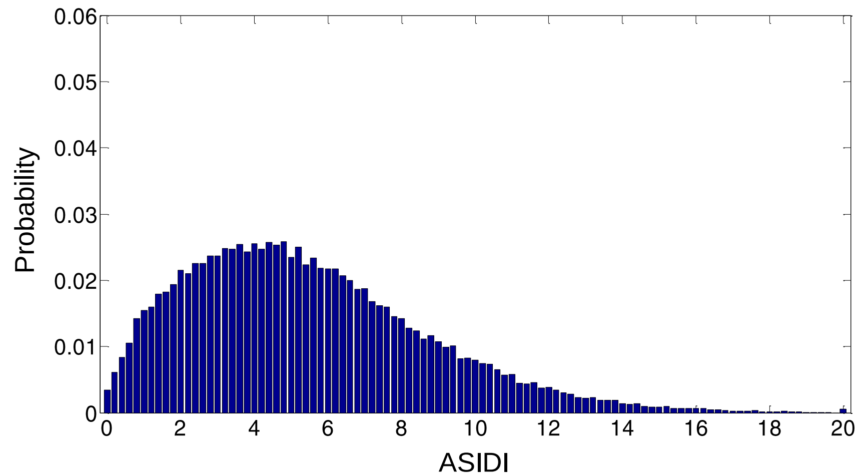

Fig. 5.33 Distribution of ASIDI for the system when β = 3.5

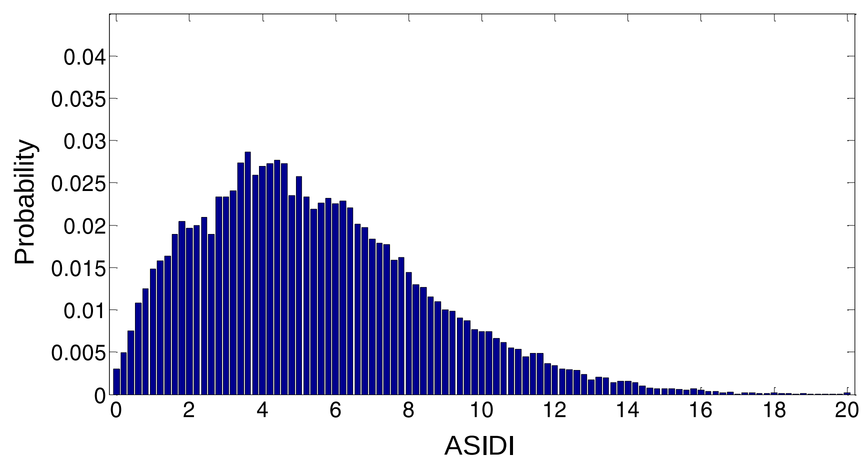

Fig. 5.34 Distribution of ASIDI for the system using fixed repair durations

## 5.4. Effect on Load Point Annual Outage Duration Distribution

Bus 6 of the RBTS consists of 4 primary or main feeders. Feeders 1 and 2 have back feed connected to each other at the end of the feeder and contain 13 load points with disconnects at each main section in the feeders. Feeder 3 consists of 4 load points while feeder 4 consists of 23 load points. Each of these feeders is unique in its customer sectors and layout of the load points.

Application of different repair duration distributions and this effect on the annual outage duration at the load points was analyzed. It is observed that the annual outage duration distributions followed the same distribution as the repair duration. Figures 5.35 to 5.38 show the distribution for Load Point 1 which has a relatively high reliability.  The prevalent effect of the switching duration of the disconnects, which is modeled as a deterministic duration of 60 minutes, have been removed to show the resemblance of the rest of the load point outage duration distribution with the repair duration distribution. This was done by removing the number of occurrences and the durations of outage due to switching action from the resultant accumulated data. With the increase in the shape parameter of the repair duration distributions, the probability of zero outage durations at Load Point 1 decreases rapidly along with the spread of the load point annual outage duration distribution.

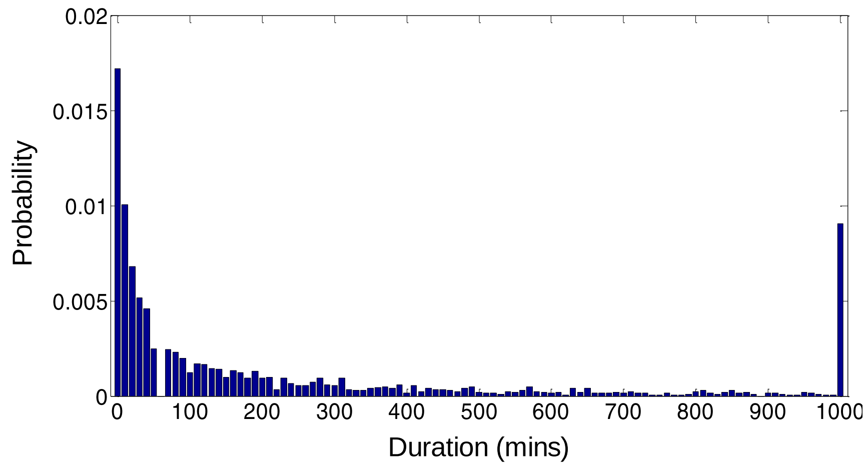


Fig. 5.35 Annual outage duration distribution for Load Point 1 when β = 0.5

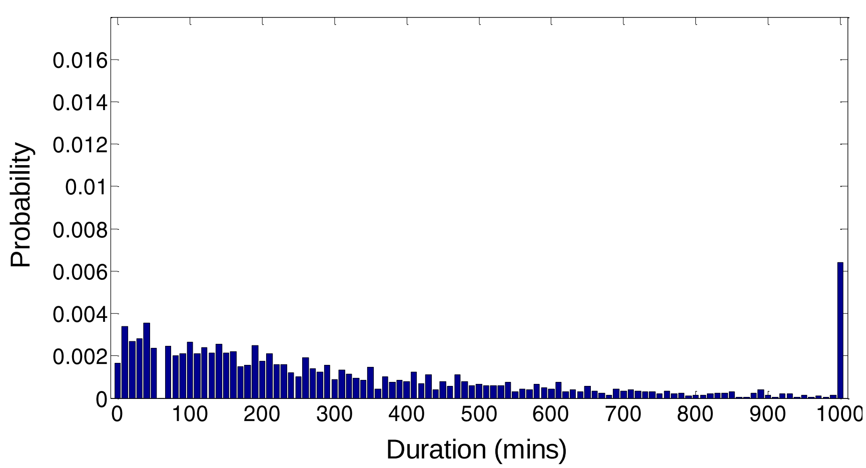


Fig. 5.36 Annual outage duration distribution for Load Point 1 when β =1

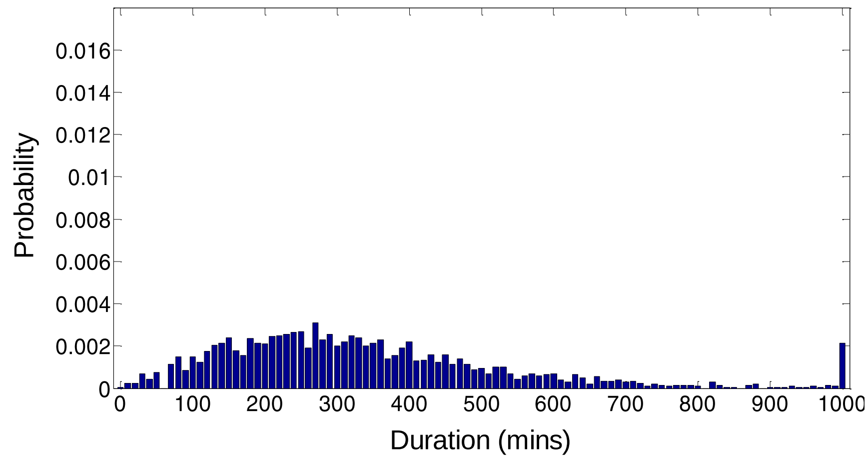


Fig. 5.37 Annual outage duration distribution for Load Point 1 when β = 2

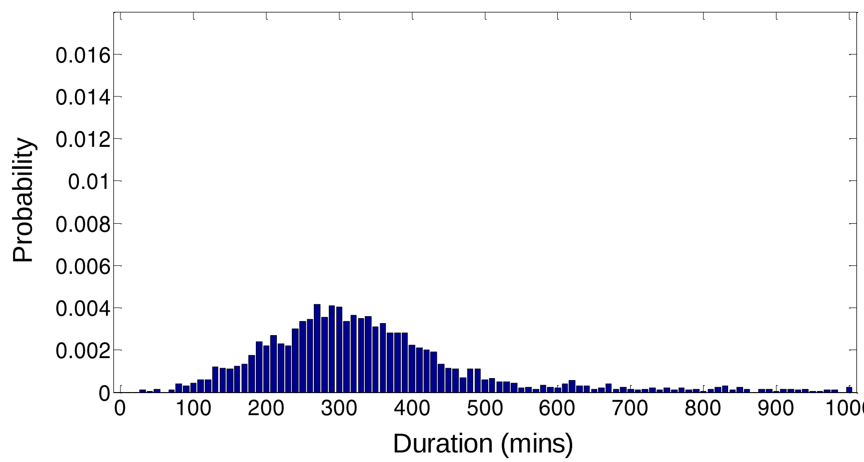


Fig. 5.38 Annual outage duration distribution for Load Point 1 when β = 3.5

### 5.5 Summary

The analysis of the use of repair duration distributions revealed that the variation in some load point expected costs is even greater than when using fixed mean repair durations. Hyper-exponential repair duration distribution resulted in bigger percentage differences in load point ECOST anywhere from 52% to 3% across the load points. This difference decreased with the increase in the shape parameter of the repair distributions. The residential customers exhibited the biggest difference while the agricultural customers had the least differences in their ECOST. This can be attributed to their respective sector CDF. The slope of the sector CDF for agricultural customers is the lowest while it is the highest for residential customers. This indicates that the sector CDF data play an important role when repair duration distributions are used to calculate the expected costs.

The variation in the load point expected costs for different repair duration distribution was more uniform with the use of system CCDF. Hyper-exponential repair distribution resulted in percentage differences of 51% to 25% across the load points. This difference also decreased with increase in the shape parameter of the repair duration distributions. The topology of the system also determined the percentage difference in the load point expected costs with respect to the repair duration distributions. More reliable load points had less difference in their ECOST when different repair duration distributions were applied. The difference was high for load points that were more unreliable. However, the variation in the ECOST with respect to the analytical values decreased with the increase in the shape parameter of repair distributions for load point and system expected costs.

Certain load point expected costs decreased by almost 45% for hyper-exponential repair duration distributions without linear extrapolation of the sector CDF. All other load point expected costs were also below their analytical values calculated without the linear extrapolation. However, the difference was negligible with normal repair distribution for all load points. The total expected cost for the system was at 34% and 8% below their analytical value for hyper-exponential and exponential repair duration distributions respectively. On the other hand, the total expected cost was up by 6% for Rayleigh repair duration distributions and 8% for normal repair duration distributions. This shows that the linear extrapolation of the sector CDF affects the system the most when hyper-exponential repair duration distributions are applied.

Various reliability indices were analyzed to see the effect of repair duration distributions on them. Customer-oriented indices SAIDI, CAIDI and IOR exhibited the same type of distribution as the repair duration distribution selected. SAIDI and CAIDI followed the repair distribution while IOR was the mirror image of SAIDI. There were no significant changes in SAIFI with the use of repair distributions. Neither were there any changes with the removal of back feed between Feeders 1 and 2 which resulted in no visible changes in the SAIFI for Feeder 1 or 2 while removal of disconnects in Feeder 1 resulted in a decrease in probability of zero failures for Feeder 1. There was also no effect of repair duration distributions on CEMI. The CEMI-3 for the system was 13.12% irrespective of the type of repair duration distribution. But CELID showed a systematic increase with the increase in the shape parameter. When the repair duration distribution is hyper-exponential, the probability of the component taking a longer time for repair is less. Hence, CELID is also low compared with when repair duration distributions with higher shape parameter values are applied. Load-oriented index ASIFI was also not affected by the type of repair duration distribution while ASIDI followed the repair duration distribution chosen.

The load point annual outage distribution also resembled the repair duration distribution selected. The load points with disconnects had their distribution skewed by the effect of the switching duration. However, the underlying distribution showed that it followed the repair duration distributions. The increase in the shape parameter in the repair duration distributions resulted in a decrease in the probability for zero failures and a decrease in the spread of the load point annual outage distribution.

# CHAPTER 6
# SUMMARY AND CONCLUSIONS

This thesis analyzes the application of various analytical and simulation techniques to evaluate customer outage costs. The analytical techniques vary in their complexity and the data utilized during the evaluation. The simulation approach also incorporates varying degrees of complexity and data to evaluate the expected customer costs at the system and load points. The variation in the customer outage costs using these analytical and simulation techniques are analyzed in this research work.

This thesis also describes the research conducted on the effect of various repair duration distributions on the customer outage costs and distribution system reliability indices. The mean or average values provide an important reliability evaluation of a distribution system. However, the mean values do not provide any information on the variation surrounding the mean of the reliability indices. Instead of the average repair duration of a failed component, various repair duration distributions are applied and the impact on the system reliability indices and their probability distributions and the customer outage costs at the system and load point levels are analyzed. The effect of repair duration distributions on the annual outage duration distribution at the load points is also studied.

Chapter 1 provides a brief overview of the power system reliability concepts. The basic power system is divided into functional zones and hierarchical levels for reliability evaluation. The development and significance of distribution system reliability evaluation is highlighted. It is noted that the customer failure statistics compiled by utilities indicate that most failures occur at the distribution level. The basic load point and system indices used for reliability evaluation of distribution systems are introduced in this chapter.

Chapter 2 provides an introduction to electric distribution systems including meshed and radial systems. The basic elements of a distribution system such as feeders, lateral sections or distributors, transformers, disconnects, fuses are also introduced in this chapter. The reliability of a distribution system can be analyzed using analytical and simulation techniques. The analytical approach provides the expected values and is convenient when evaluating simple systems. The simulation techniques provide the ability to deal with the stochastic nature of the power system parameters and complex network systems. It can also provide distributions of the load point and system reliability indices, which are defined in this chapter. The Roy Billinton Test System (RBTS) used in this research work is also illustrated. The research focuses on the distribution network of Bus 6 of the RBTS.

Reliability cost/worth analysis is an essential concept to evaluate the benefit or cost associated with the reliability of the power system and this is introduced in Chapter 2. An increase in investment in infrastructure will result in an increase in the reliability of the system and hence, decrease in the customer interruption costs. Customer damage functions (CDF) show the relationship between the costs and the outage durations for a particular sector of customers. This information is usually obtained directly from the customers through surveys. Due to limitations in collecting data, any outage durations beyond the survey data, and costs associated with them, need to be determined through extrapolation. This technique is explained in this chapter. Feeder composite customer damage functions (CCDF) and System CCDF are also evaluated for each of the feeders at Bus 6 of the RBTS since the load composition on the feeder and system are known. Chapter 2 also introduces the expected customer outage costs (ECOST) which can then be calculated using CCDF through analytical and simulation approaches. Various standard probability distributions applied in the research are also explained in this chapter. These probability distributions are applied to the repair durations and their effect on the expected customer cost and the reliability indices is analyzed in subsequent chapters.

Chapter 3 introduces the analytical and time sequential Monte Carlo simulation techniques. The failure mode and effect analysis (FMEA) used in the analytical technique is illustrated by applying it on Feeder 3 on Bus 6 of the RBTS. Various system indices are calculated for Feeder 3 using this approach. State sampling and time sequential Monte Carlo simulation techniques are briefly introduced in this chapter. This research work uses the sequential Monte Carlo simulation technique.

A computer program based on time sequential Monte Carlo simulation technique was also developed for this research work. The concept involved in developing this computer program to evaluate load point and system indices is described in Chapter 3. Converting a uniformly distributed random number to another distribution is also explained in this chapter. This method can then be applied to generate various repair duration distributions for this research work. The result obtained by using this program is validated by calculating the system indices for Feeder 3 of Bus 6 of the RBTS and comparing it with the analytical results. This is further verified by comparing the results for all load point indices and system indices of Bus 6 using both the computer program and the analytical approach.

Chapter 4 analyzes both analytical and Monte Carlo simulation approaches to evaluate the expected customer outage costs at the load points and at the system level. The techniques are divided into eight separate cases. These techniques vary from the simplest analytical approach to a more complex approach using Monte Carlo time sequential simulation techniques in the evaluation of ECOST. The data requirement of the events and interruption costs increases with the increase in complexity of these techniques. This results in more accurate evaluation of ECOST. However, utilities may face higher investment and operation costs to collect the additional data. The variation in the results using these techniques may provide some indication of whether the application of more complex techniques and hence the additional investment costs can be justified.

Case 1 is the simplest analytical technique and uses the SAIFI and the equivalent interruption cost from the system CCDF for the system CAIDI to evaluate the total expected cost. This technique resulted in an ECOST of 176.2 k$/yr. The modified version of this technique, Case 2, used the SAIFI and CAIDI information from the feeder level to evaluate the expected cost at the feeder and system level using the Feeder CCDF. The total expected cost was 99.7 k$/yr which is a decrease of 43.4% from that obtained using the simplest technique.

In the detailed analytical technique in Case 3, the system CCDF is used to evaluate the ECOST at the load point and system levels. The total system expected cost was 270.6 k$/yr which is a 53.6% increase from Case 1 and 171.4% increase from Case2. The load point ECOST is affected by the peak load at the load point and the topology of the system. Since a CCDF assumes a proportional distribution of all load curtailment, considering each load point with the same customer mix by using such a CCDF resulted in the highest total system ECOST. Case 4 analyzes the variation of load point ECOST using sector CDF. The customers at load points whose sector CDF is higher than other sector CDF had lower load point expected cost when evaluated using the system CCDF. Load Point 40 had a 300% higher expected cost when using the system CCDF compared to the sector CDF. The total system ECOST decreased by 57.5% with the application of sector CDF to 115.1 k$/yr. Hence, the type of customers at the load points and the topology of the system need to be examined before using the system CCDF to evaluate the expected customer outage cost.

Case 5 considers the variations in load point and system expected costs when the customer mix is considered at the load points. The customers at load points considered so far were all homogenous in nature. However, a mixture of various customer sectors may exist at a load point. Feeder 3 consists of 35.8% commercial and 64.2% industrial customers by load composition. The resultant feeder CCDF was used to evaluate the feeder expected cost of 30.9 k$/yr which was an increase of only 0.3% from that calculated in Case 4 using the sector CDF. Therefore, understanding the type of customers at a load point and feeder can provide a very accurate value of ECOST at that point.

Cases 6 and 7 include the application of the time sequential Monte Carlo simulation technique. The mean repair durations of the components are used to obtain the expected customer costs at the load point and system levels. Case 6 considers the variation in the ECOST when the system CCDF is used. This shows an increase of 5.2% in the ECOST to that in Case 3. The sector CDF are used in Case 7 and this resulted in an increase of 5.5% in the ECOST to that in Case 4. This suggests that the use of Monte Carlo simulation technique provides results that are close to that of analytical approach in calculating expected customer costs. The utilization of the system CCDF will always result in higher expected cost values than the use of the sector CDF whether the technique used is analytical or simulation in nature.

Repair duration distributions are applied to evaluate the load point and system level expected customer outage costs in Case 8. The sector CDF are used and the variation in the costs is compared with that in Case 4. It is shown that as the repair duration distributions vary from hyper-exponential to normal distribution, the load point and system level expected customer outage costs tend to move closer to the analytical values obtained in Case 4. Application of a hyper-exponential repair duration distribution resulted in an increase of 30% in the total system ECOST to 150.4 k$/yr while a normal repair duration distribution resulted in an increase of 9%.

Chapter 5 examines the application of repair duration distributions on the expected customer outage costs and the system reliability indices. The sector CDF were used and comparisons are made with the analytical results obtained in Case 4 in Chapter 4. Hyper-exponential repair duration distributions resulted in increases in the ECOST of 52% to 3% across the load points compared to Case 4, while normal repair duration distributions resulted in increases in the load point ECOST of 30% to 1%. The load points with residential customers displayed the most variation in the expected costs while the agricultural sector had the least variation. This can be attributed to their respective sector CDF. The slope of the sector CDF for agricultural customers is the lowest while it is the highest for residential customers. This indicates that the sector CDF data play an important role when repair duration distributions are used to calculate the expected costs.

Similar comparison using system CCDF showed that the variation in the load point expected costs for different repair duration distributions was more uniform. Hyper-exponential repair duration distributions resulted in percentage differences in the ECOST of 51% to 25% across the load points compared with that in Case 3 while normal repair duration distributions resulted in variations of 35% to 4%. The differences in the ECOST at load points 1 to 13 at Feeders 1 and 2 were much smaller and uniform due to repair duration distributions applied than when these results are compared with the analytical values. This is since Feeders 1 and 2 have a back feed connected between them. The load points at the end of Feeder 4 were the most unreliable and the differences in the ECOST due to application of repair duration distributions was the most significant. This is even more evident when sector CDF are used. The application of repair duration distributions enhances the effect of load point peak load, the topology of the system and whether CDF or CCDF is used. However, the difference in the expected costs compared to the analytical values is reduced as the shape parameter in the repair duration distributions is increased. The effect of linear extrapolation of CDF on the ECOST when different repair duration distributions are applied is also analyzed in Chapter 5. Without linear extrapolation of the CDF, the expected costs evaluated using repair duration distributions which have a larger spread were affected the most and they showed a significant decrease compared to the analytical values. The load points experiencing the lowest level of reliability in the system showed a decrease in their ECOST by almost 45% when a hyper-exponential repair duration distribution was applied. The impact was less and uniform across the load points when a normal repair duration distribution is used. This suggests that the choice of a linear extrapolation algorithm used in the CDF extrapolation will impact the expected customer outage costs the most when repair duration distributions having larger standard deviations are applied.

Chapter 5 also analyzes the impact of different repair duration distributions on the probability distributions of system indices and load point annual outage durations. The customer-oriented indices SAIDI and CAIDI followed a similar distribution as the selected repair duration distribution. The IOR results were similar to that of SAIDI. Removal of back feed between Feeders 1 and 2 resulted in a probability distribution of SAIDI with higher spread and hence, higher probability of larger values for SAIDI, for both feeders. The repair duration distributions had no effect on SAIFI. Removal of back feed between Feeders 1 and 2 also had no visible changes on SAIFI for Feeders 1 or 2. However, the removal of disconnects in Feeder 1 resulted in a decrease in the probability of zero failures for Feeder 1. The customers experiencing more than 3 interruptions per year, CEMI, stayed the same at 13.12% regardless of the type of repair duration distributions used. Customers experiencing longest interruption duration, CELID, of 5 hours or more increased with the increase in shape parameter used in the repair duration distributions. Hence, for the exponential repair duration distribution, the probability of longer repair duration for a component is low and this is reflected in CELID having a lower percentage value compared to when a normal repair duration distribution is applied. The load-oriented index ASIFI was also not affected by the type of repair duration distributions used, while the probability distribution of ASIDI followed that of the repair duration distribution.

The impact on the load point annual outage duration due to the kind of repair duration distribution applied is direct. The load point annual outage distribution resembles the repair duration distribution. The load points with disconnects in the main and lateral sections leading to the load point had their distribution skewed by the effect of the fixed switching duration of 1.0 hour. However, the underlying distribution showed that it followed the repair duration distributions. There is a decrease in the probability for zero failures and a decrease in the spread of the load point annual outage distribution as the shape parameter values is increased to obtain the relevant repair duration distribution.

The analysis conducted in this research work and described in this thesis shows that there exists significant variations in the expected customer outage costs depending on the topology of the system, types of customers at the load points and whether system CCDF or sector CDF are applied in both analytical and simulation approaches. Application of system CCDF tends to overstate the total ECOST if a significant number of customers have sector CDFs higher than the system CCDF. The Monte Carlo simulation technique provides similar results compared the basic analytical approach when comparing the variation in ECOST.

The results presented in this research work show that the type of repair duration distribution applied can result in considerable variation in system and load point ECOST. Frequency-oriented reliability indices are not affected by the application of repair duration distributions. Duration-oriented reliability indices are susceptible to the types of repair duration distribution applied and the probability distribution of these indices tends to follow the repair duration distribution.

This research work provides a basic guide to the difference in expected customer outage costs and probability distributions of the reliability indices that can be expected when choosing a particular evaluation technique using sector CDF or CCDF, and type of repair duration distribution. It also highlights the importance of collecting accurate data on types of customers present in the system, customer interruption costs and repair durations for reliability cost/worth evaluation.

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# APPENDIX A

## A. 1 Input Data for Bus 6 of the RBTS

Table A.1. Data for the main sections, Bus 6

| Main Section (i) | Disconnect Type | Failure Rate λ (occ./yr) | Repair Time (hr) | Switching time (hr) |
|---|---|---|---|---|
| 1 | 0 | 0.039 | 5 | 1 |
| 2 | 1 | 0.0487 | 5 | 1 |
| 3 | 1 | 0.039 | 5 | 1 |
| 4 | 1 | 0.039 | 5 | 1 |
| 5 | 1 | 0.052 | 5 | 1 |
| 6 | 1 | 0.0487 | 5 | 1 |
| 7 | 1 | 0.039 | 5 | 1 |
| 8 | 0 | 0.0487 | 5 | 1 |
| 9 | 1 | 0.039 | 5 | 1 |
| 10 | 1 | 0.0487 | 5 | 1 |
| 11 | 1 | 0.0487 | 5 | 1 |
| 12 | 1 | 0.039 | 5 | 1 |
| 13 | 1 | 0.052 | 5 | 1 |
| 14 | 0 | 0.0487 | 5 | 1 |
| 15 | 1 | 0.052 | 5 | 1 |
| 16 | 1 | 0.039 | 5 | 1 |
| 17 | 1 | 0.0487 | 5 | 1 |
| 18 | 0 | 0.182 | 5 | 1 |
| 19 | 0 | 0.1625 | 5 | 1 |
| 20 | 0 | 0.104 | 5 | 1 |
| 21 | 0 | 0.0585 | 5 | 1 |
| 22 | 0 | 0.104 | 5 | 1 |
| 23 | 0 | 0.1625 | 5 | 1 |
| 24 | 0 | 0.104 | 5 | 1 |
| 25 | 0 | 0.0585 | 5 | 1 |
| 26 | 1 | 0.208 | 5 | 1 |
| 27 | 0 | 0.182 | 5 | 1 |
| 28 | 0 | 0.2275 | 5 | 1 |
| 29 | 0 | 0.104 | 5 | 1 |
| 30 | 0 | 0.182 | 5 | 1 |
| 31 | 0 | 0.208 | 5 | 1 |
| 32 | 0 | 0.1625 | 5 | 1 |
| 33 | 0 | 0.208 | 5 | 1 |
| 34 | 0 | 0.104 | 5 | 1 |
| 35 | 0 | 0.182 | 5 | 1 |
| 36 | 0 | 0.1625 | 5 | 1 |

| | | | | |
|---|---|---|---|---|
| 37 | 0 | 0.208 | 5 | 1 |
| 38 | 0 | 0.182 | 5 | 1 |
| 39 | 0 | 0.1625 | 5 | 1 |
| 40 | 0 | 0.104 | 5 | 1 |
| 41 | 0 | 0.208 | 5 | 1 |
| 42 | 0 | 0.182 | 5 | 1 |

Table A.2 Data for the lateral sections, Bus 6

| Node | Lateral Section (i) | Fuse | Transf | Failure Rate of Lateral section λL (occ./yr) | Repair Time for lateral section RL (hr) | Switching Time Rs (hr) | Failure Rate of Transformer λT (occ/yr) | Repair time for Transformer RT (hr) |
|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 2 | 2 | 1 | 1 | 0.052 | 5 | 1 | 0.015 | 10 |
| 3 | 3 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 4 | 4 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 5 | 5 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 6 | 6 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 7 | 7 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 8 | 8 | 1 | 1 | 0.052 | 5 | 1 | 0.015 | 10 |
| 9 | 9 | 1 | 1 | 0.052 | 5 | 1 | 0.015 | 10 |
| 10 | 10 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 11 | 11 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 12 | 12 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 13 | 13 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 14 | 14 | 1 | 0 | 0.039 | 5 | 1 | 0 | 0 |
| 15 | 15 | 1 | 0 | 0.04875 | 5 | 1 | 0 | 0 |
| 16 | 16 | 1 | 0 | 0.052 | 5 | 1 | 0 | 0 |
| 17 | 17 | 1 | 0 | 0.039 | 5 | 1 | 0 | 0 |
| 18 | 18 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 19 | 19 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 20 | 20 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 21 | 21 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 22 | 22 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 23 | 23 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 24 | 24 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 26 | 25 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 27 | 26 | 1 | 1 | 0.039 | 5 | 1 | 0.015 | 10 |
| 28 | 27 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 30 | 28 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 31 | 29 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 32 | 30 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 33 | 31 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 34 | 32 | 1 | 1 | 0.052 | 5 | 1 | 0.015 | 10 |
| 35 | 33 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 36 | 34 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 37 | 35 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 38 | 36 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 39 | 37 | 1 | 1 | 0.04875 | 5 | 1 | 0.015 | 10 |
| 40 | 38 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 41 | 39 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |
| 42 | 40 | 1 | 1 | 0 | 0 | 1 | 0.015 | 10 |

Table A.3 Data for the load points, Bus 6

| Load Point | Node | Lateral Section | Load (MW) | NumCust | Type |
|---|---|---|---|---|---|
| 1 | 1 | 1 | 0.3171 | 138 | R |
| 2 | 2 | 2 | 0.3229 | 126 | R |
| 3 | 3 | 3 | 0.3171 | 138 | R |
| 4 | 4 | 4 | 0.3229 | 126 | R |
| 5 | 5 | 5 | 0.3864 | 118 | R |
| 6 | 6 | 6 | 0.3864 | 118 | R |
| 7 | 7 | 7 | 0.2964 | 147 | R |
| 8 | 8 | 8 | 0.2964 | 147 | R |
| 9 | 9 | 9 | 0.3171 | 138 | R |
| 10 | 10 | 10 | 0.2964 | 147 | R |
| 11 | 11 | 11 | 0.3229 | 126 | R |
| 12 | 12 | 12 | 0.3698 | 132 | R |
| 13 | 13 | 13 | 0.3698 | 132 | R |
| 14 | 14 | 14 | 0.8500 | 10 | C |
| 15 | 15 | 15 | 1.9670 | 1 | I |
| 16 | 16 | 16 | 1.0830 | 1 | I |
| 17 | 17 | 17 | 0.8500 | 10 | C |
| 18 | 18 | 18 | 0.2964 | 147 | R |
| 19 | 19 | 19 | 0.3229 | 126 | R |
| 20 | 20 | 20 | 0.6517 | 1 | A |
| 21 | 21 | 21 | 0.6860 | 1 | A |
| 22 | 22 | 22 | 0.3698 | 132 | R |
| 23 | 23 | 23 | 0.2964 | 147 | R |
| 24 | 24 | 24 | 0.7965 | 1 | A |
| 25 | 26 | 25 | 0.2776 | 79 | R |
| 26 | 27 | 26 | 0.7375 | 1 | A |
| 27 | 28 | 27 | 0.2831 | 76 | R |
| 28 | 30 | 28 | 0.2776 | 79 | R |
| 29 | 31 | 29 | 0.2831 | 76 | R |

| | | | | | |
|---|---|---|---|---|---|
| 30 | 32 | 30 | 0.6517 | 1 | A |
| 31 | 33 | 31 | 0.2776 | 79 | R |
| 32 | 34 | 32 | 0.5025 | 1 | A |
| 33 | 35 | 33 | 0.2831 | 76 | R |
| 34 | 36 | 34 | 0.6517 | 1 | A |
| 35 | 37 | 35 | 0.6860 | 1 | A |
| 36 | 38 | 36 | 0.2776 | 79 | R |
| 37 | 39 | 37 | 0.5025 | 1 | A |
| 38 | 40 | 38 | 0.7375 | 1 | A |
| 39 | 41 | 39 | 0.2831 | 76 | R |
| 40 | 42 | 40 | 0.7965 | 1 | A |

where,

R = Residential customers

A = Agricultural customers

C = Commercial customers

I = Industrial customers

Table A.4 Data for the feeders, Bus 6

| MSStart | MSEnd | LSStart | LSEnd | ASupply | Rs (hr) | SF | Node |
|---|---|---|---|---|---|---|---|
| 1 | 7 | 1 | 7 | 1 | 1 | 0 | 0 |
| 8 | 13 | 8 | 13 | 1 | 1 | 0 | 0 |
| 14 | 17 | 14 | 17 | 0 | 1 | 0 | 0 |
| 18 | 29 | 18 | 27 | 0 | 1 | 0 | 0 |
| 33 | 37 | 31 | 35 | 0 | 1 | 4 | 25 |
| 30 | 32 | 28 | 30 | 0 | 1 | 4 | 29 |
| 38 | 42 | 36 | 40 | 0 | 1 | 4 | 29 |

# APPENDIX B

## B.1 Probability Distributions of the System Indices for Feeder 1:

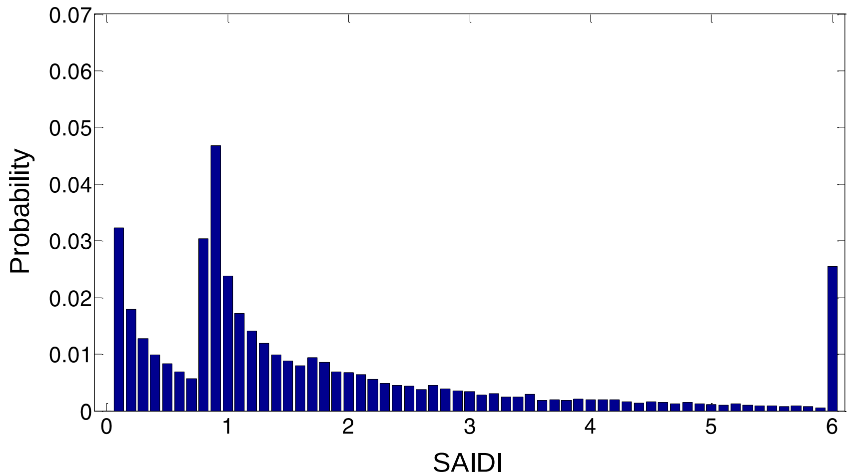


Fig. B.1 Distribution of SAIDI>0 when β = 0.5

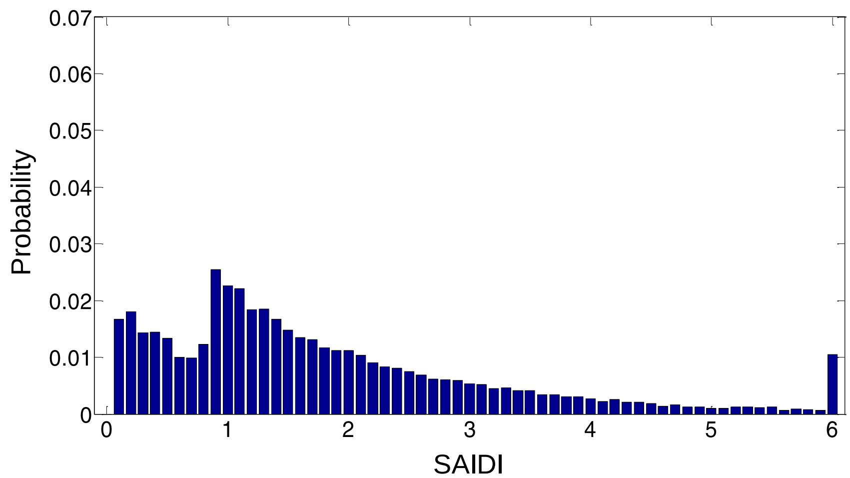


Fig. B.2 Distribution of SAIDI>0 when β = 1

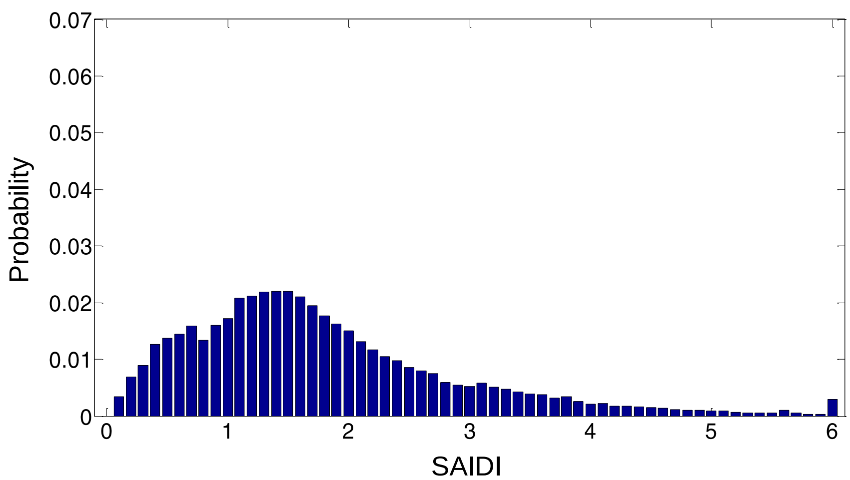


Fig. B.3 Distribution of SAIDI>0 when β = 2

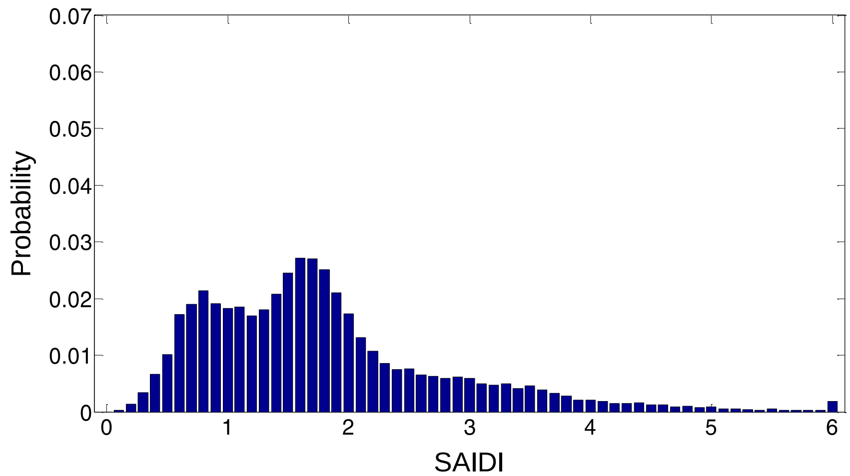


Fig. B.4 Distribution of SAIDI>0 when β = 3.5

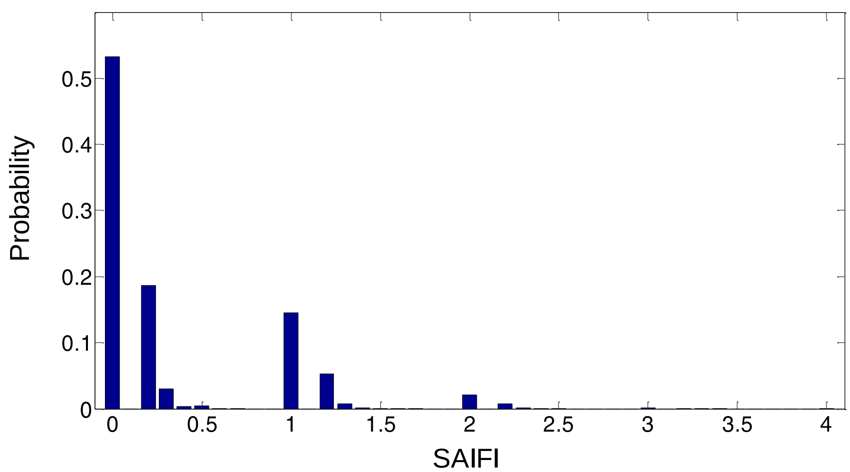


Fig. B.5 Distribution of SAIFI

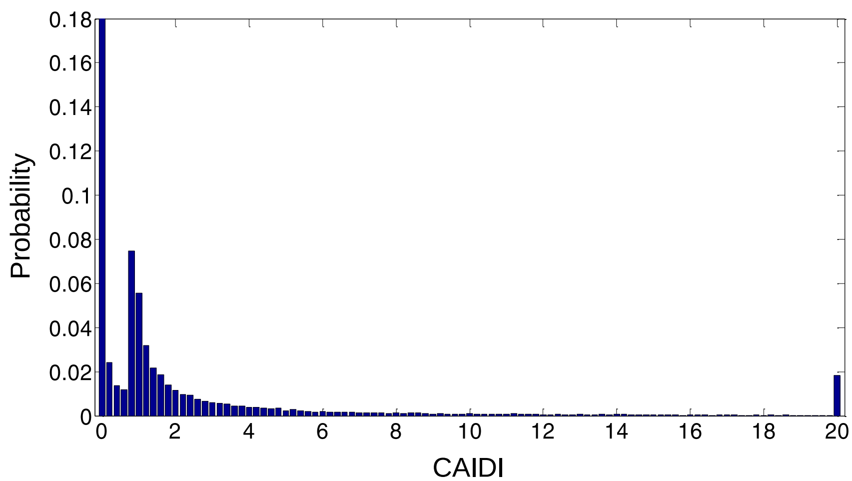


Fig. B.6 Distribution of CAIDI when β = 0.5

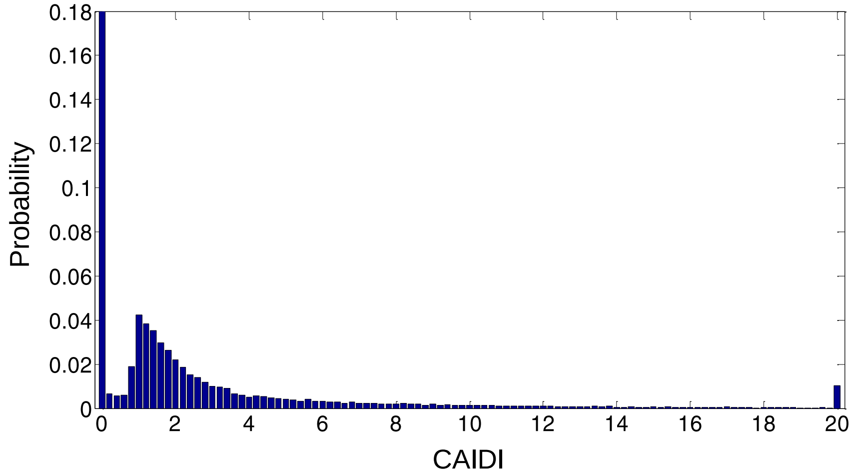

Fig. B.7 Distribution of CAIDI when β = 1

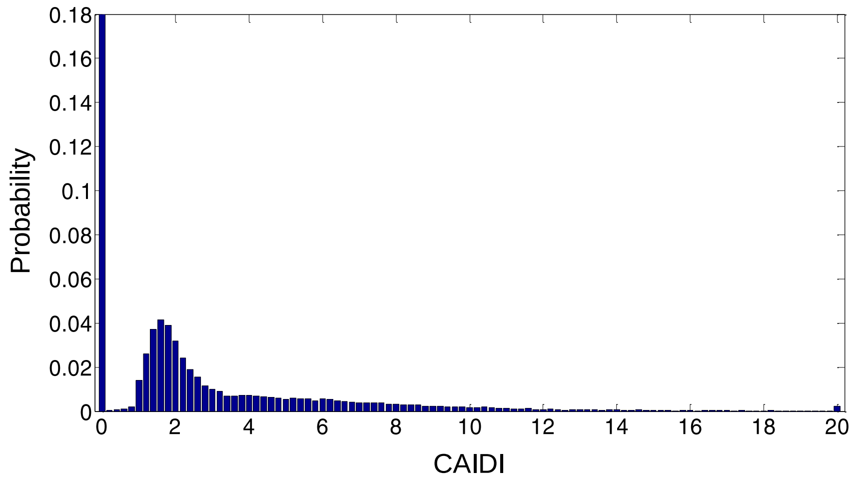

Fig. B.8 Distribution of CAIDI when β = 2

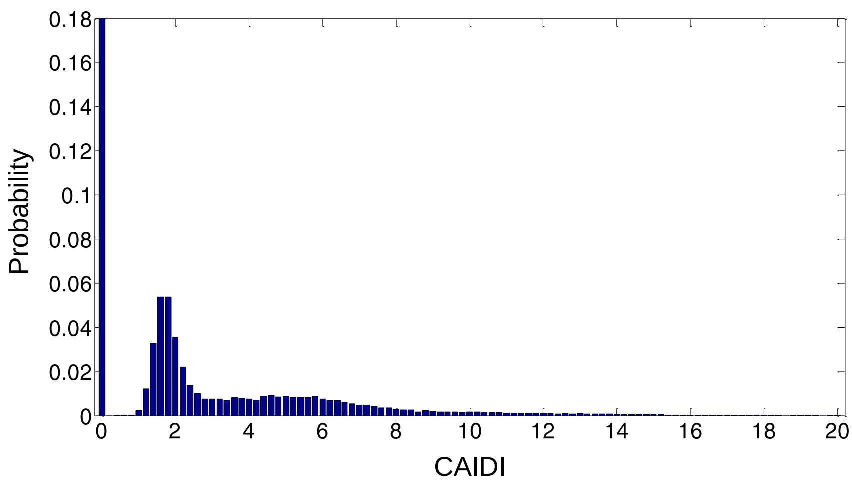

Fig. B.9 Distribution of CAIDI when β = 3.5

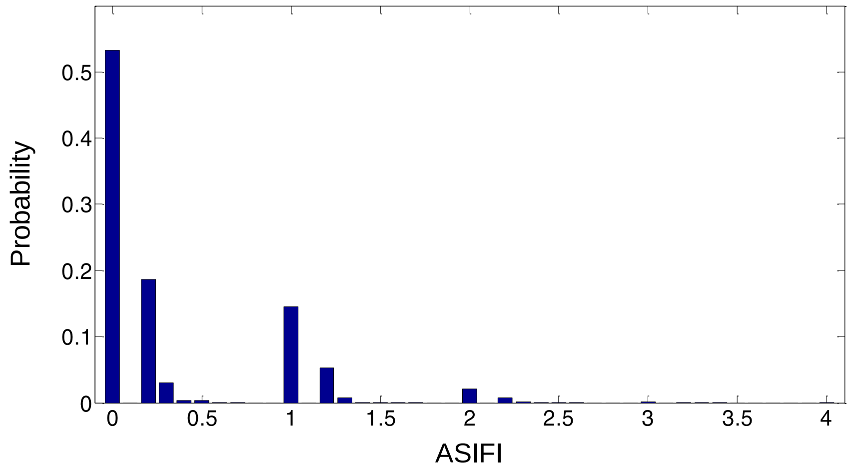

Fig. B.10 Distribution of ASIFI

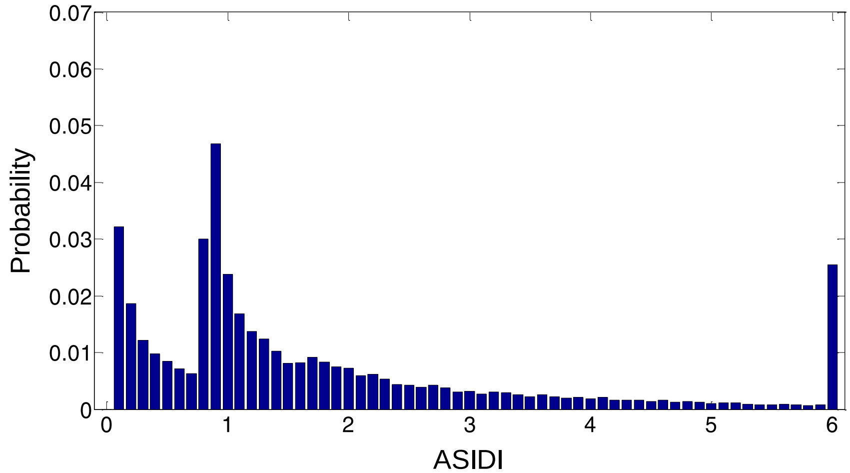

Fig. B.11 Distribution of ASIDI>0 when β = 0.5

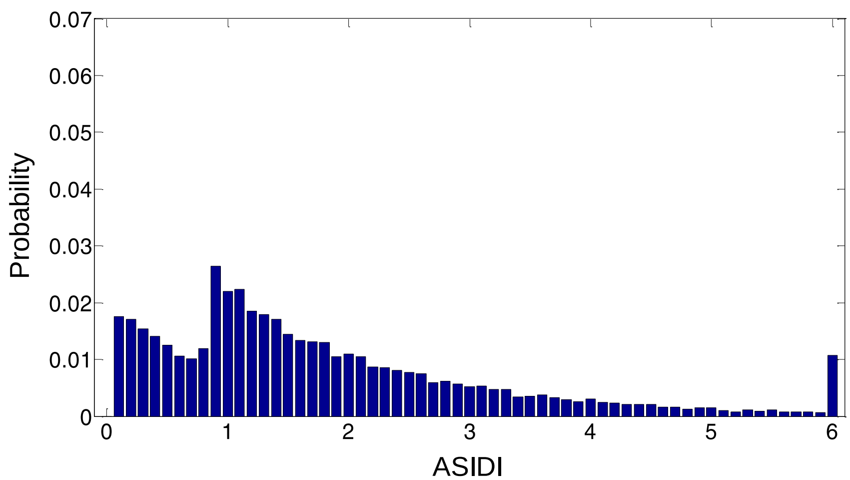

Fig. B.12 Distribution of ASIDI>0 when β = 1

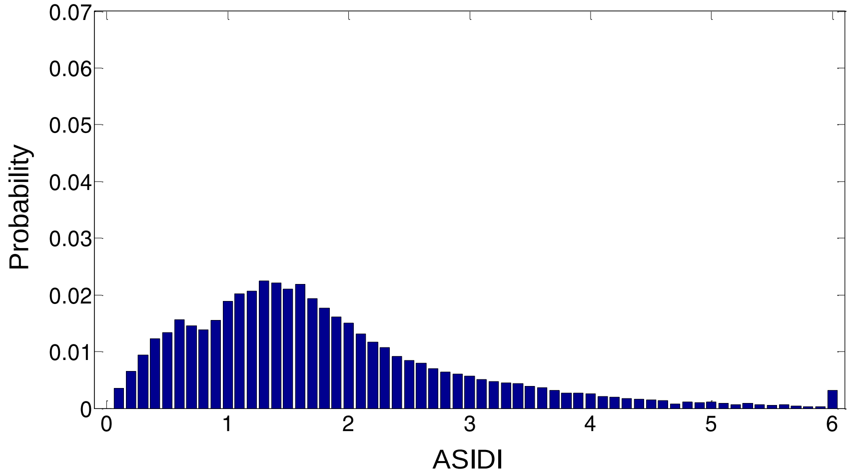


Fig. B.13 Distribution of ASIDI>0 when β = 2

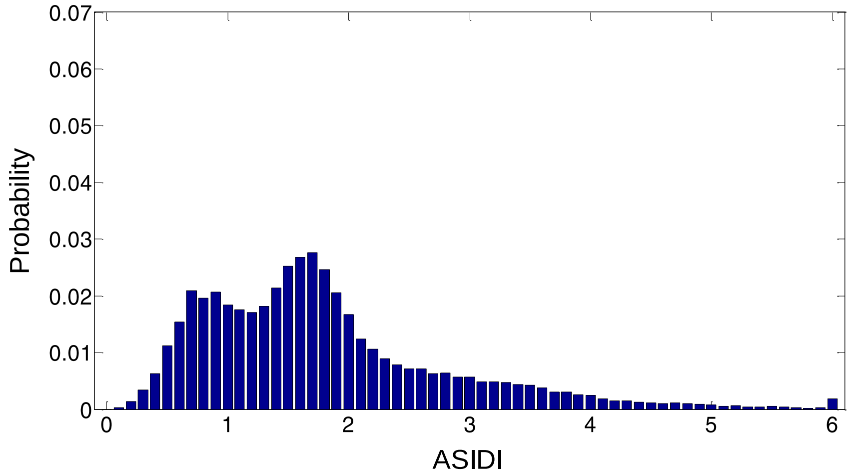


Fig. B.14 Distribution of ASIDI>0 when β = 3.5

**B.2 Probability Distributions of the System Indices for Feeder 2**

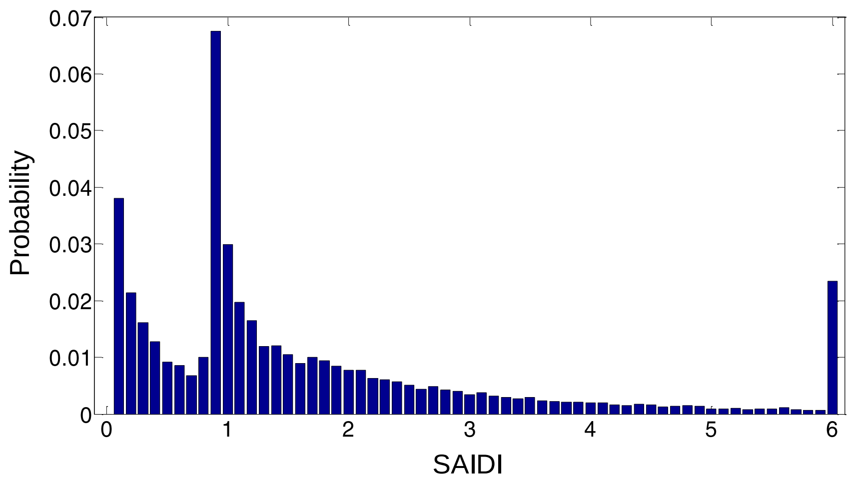


Fig. B.15 Distribution of SAIDI>0 when β = 0.5

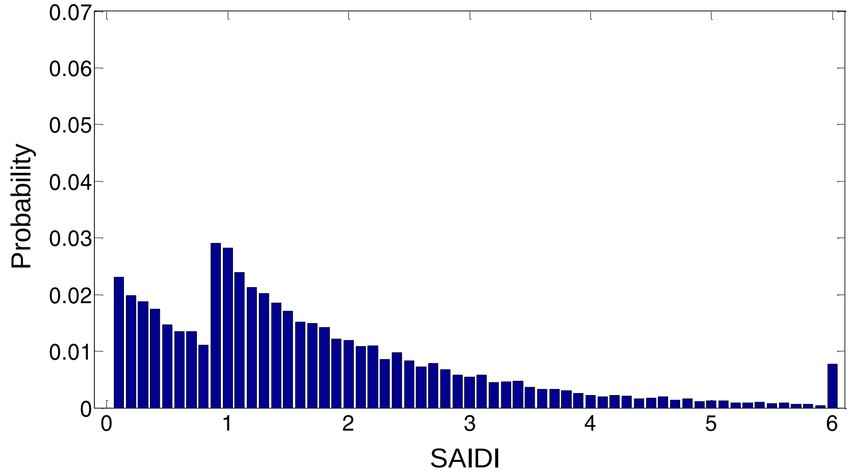

Fig. B.16 Distribution of SAIDI>0 when β = 1

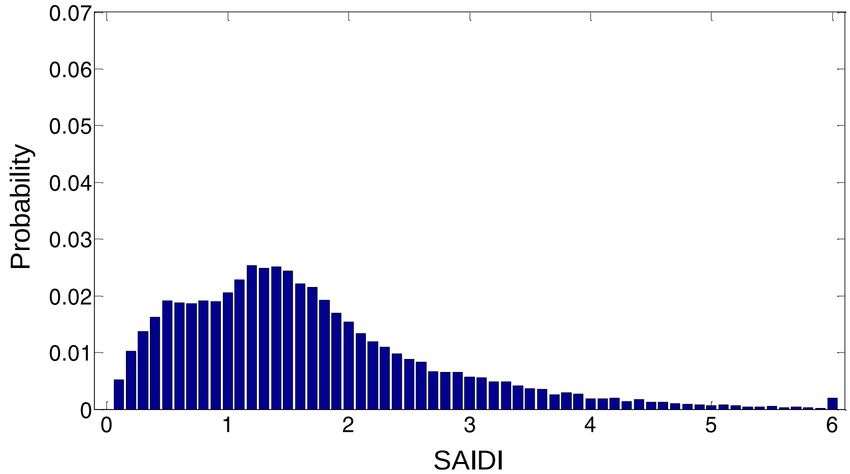

Fig. B.17 Distribution of SAIDI>0 when β = 2

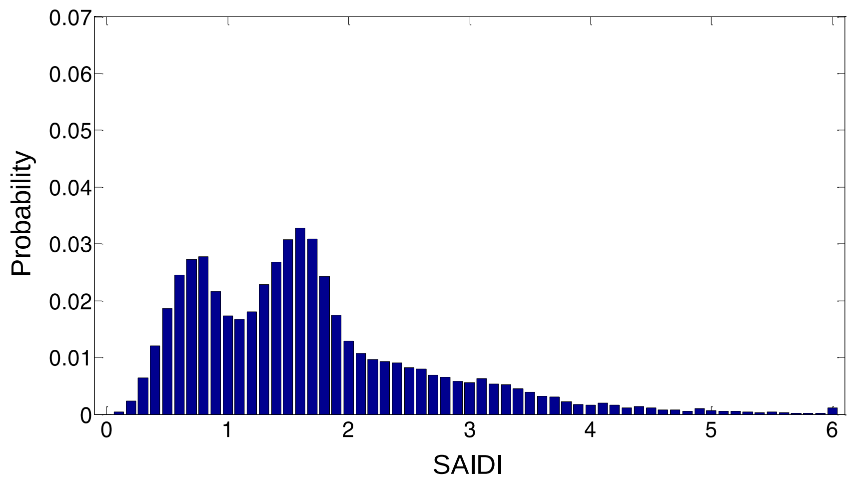

Fig. B.18 Distribution of SAIDI>0 when β = 3.5

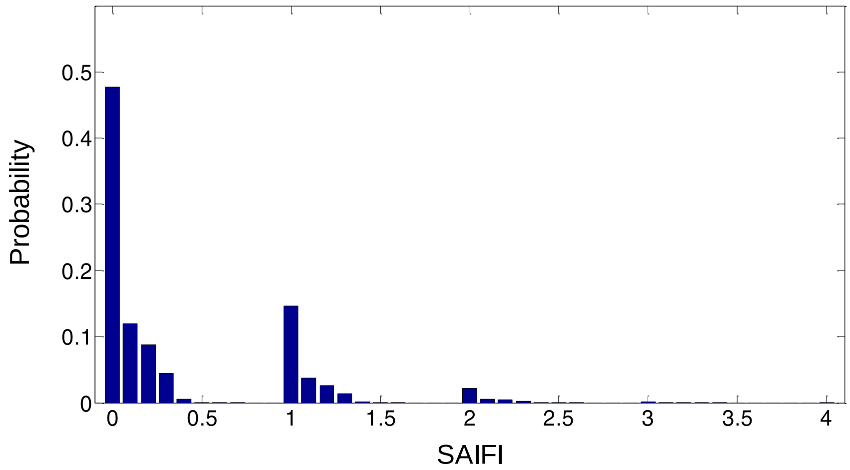


Fig. B.19 Distribution of SAIFI

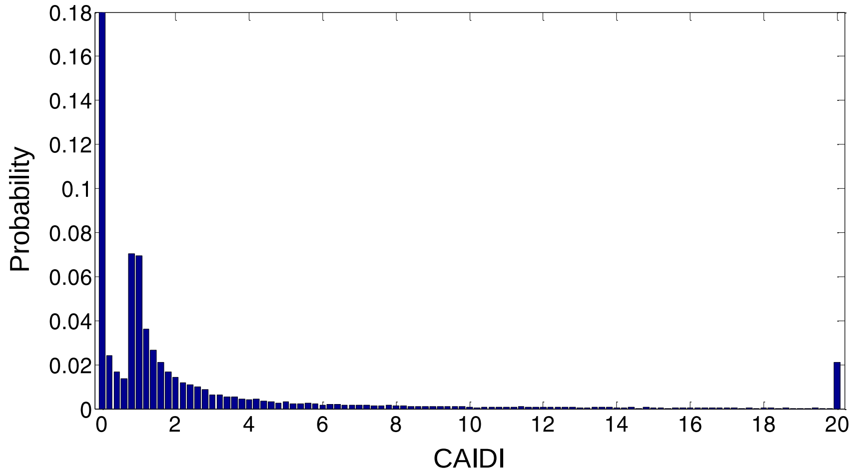


Fig. B.20 Distribution of CAIDI when β = 0.5

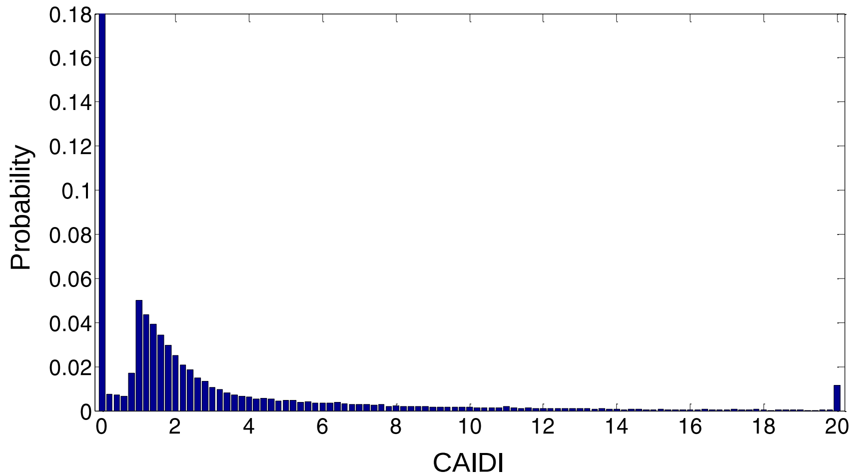


Fig. B.21 Distribution of CAIDI when β = 1

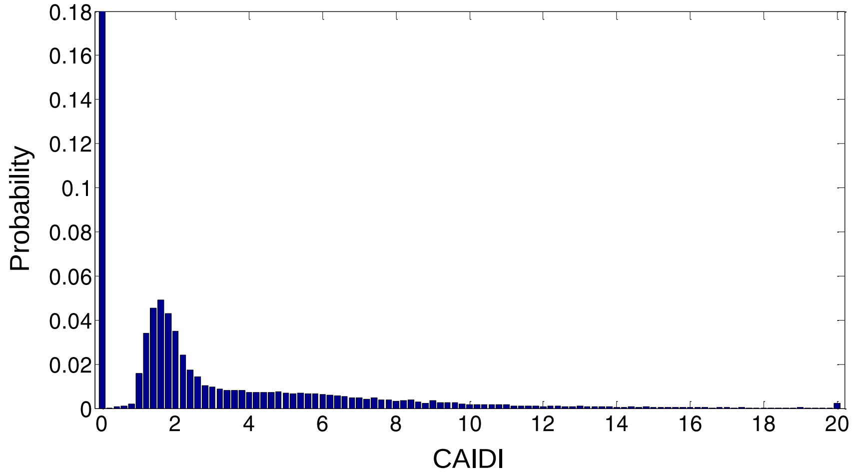

Fig. B.22 Distribution of CAIDI when β = 2

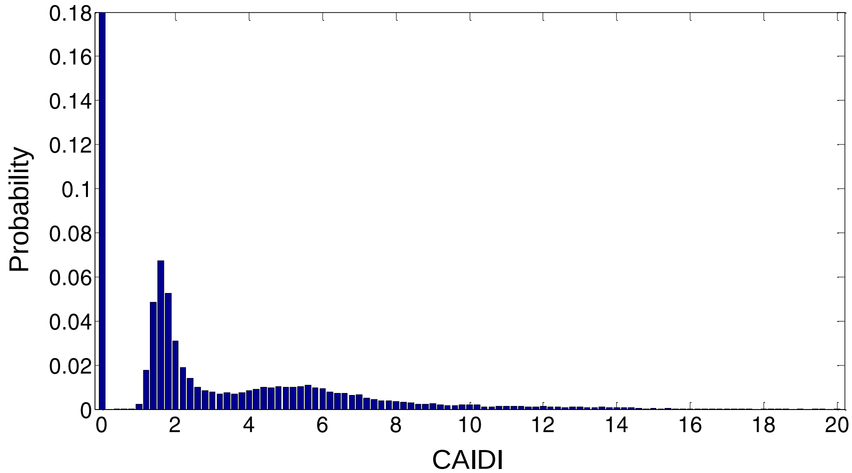

Fig. B.23 Distribution of CAIDI when β = 3.5

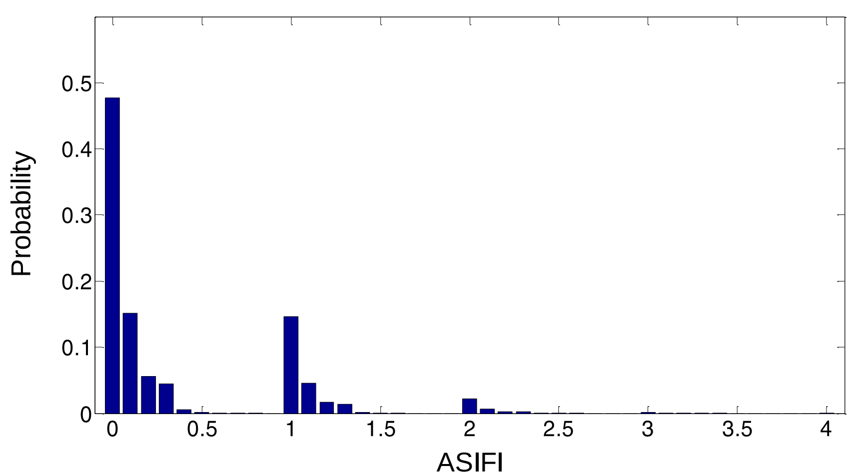

Fig. B.24 Distribution of ASIFI

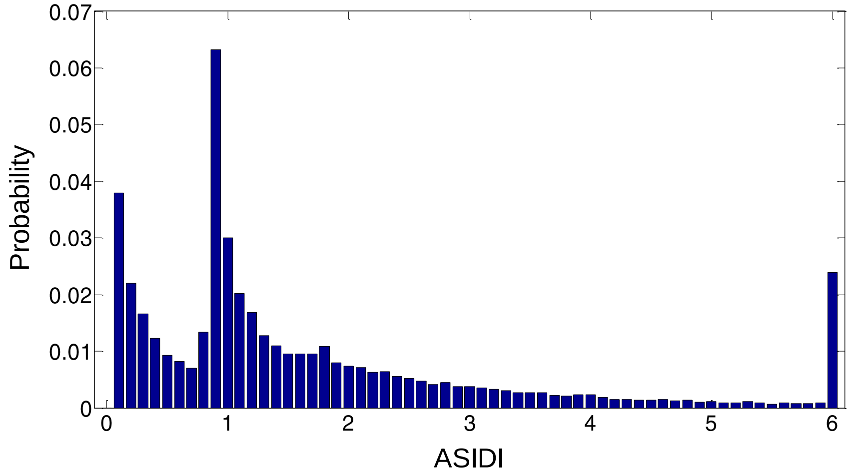

Fig. B.25 Distribution of ASIDI>0 when β = 0.5

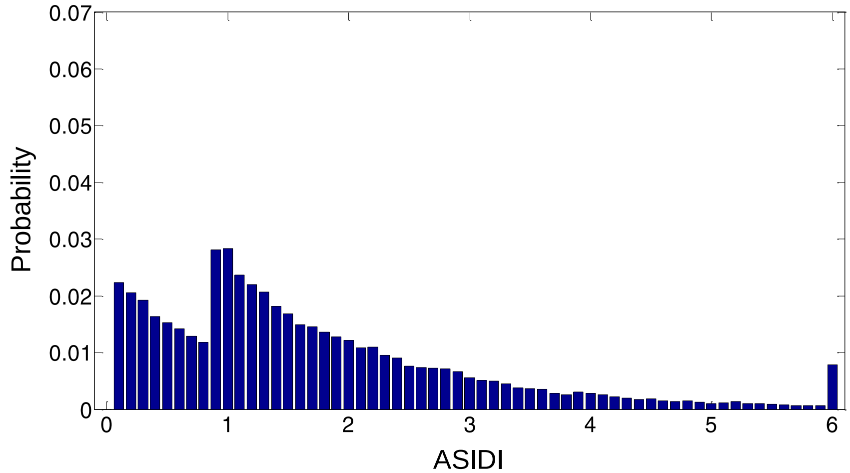

Fig. B.26 Distribution of ASIDI>0 when β = 1

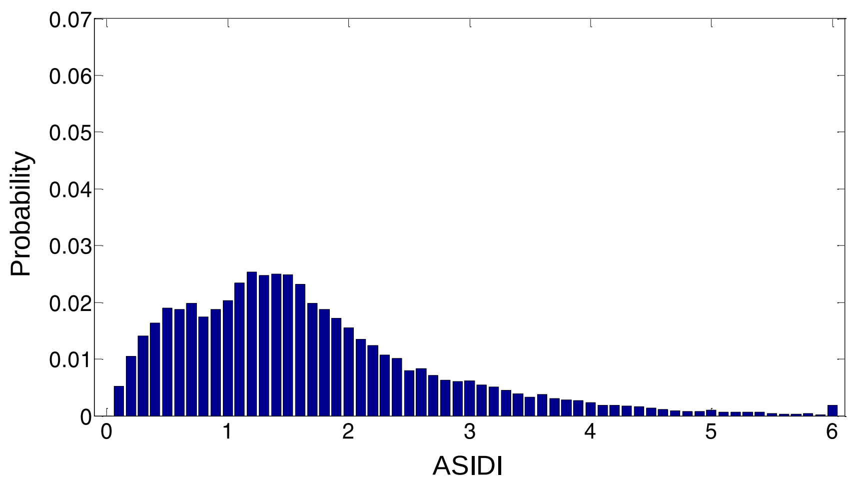

Fig. B.27 Distribution of ASIDI>0 when β = 2

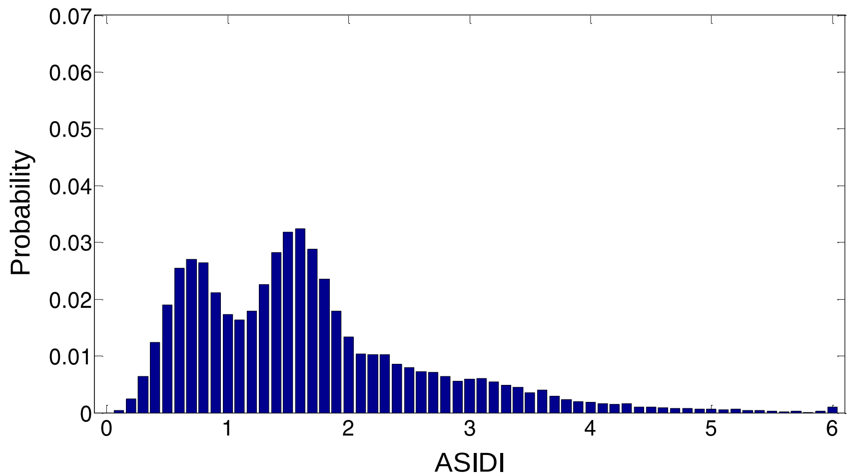


Fig. B.28 Distribution of ASIDI>0 when β = 3.5

**B.3 Probability Distributions of the System Indices of Feeder 3**

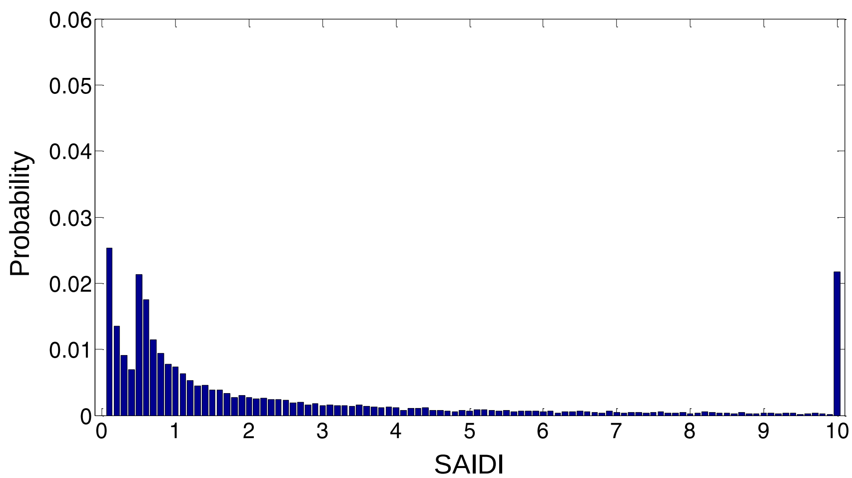


Fig. B.29 Distribution of SAIDI>0 when β = 0.5

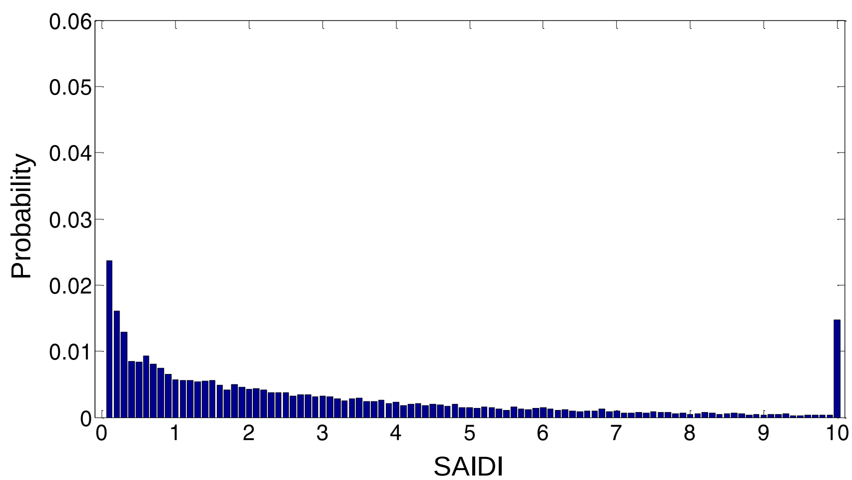


Fig. B.30 Distribution of SAIDI>0 when β = 1

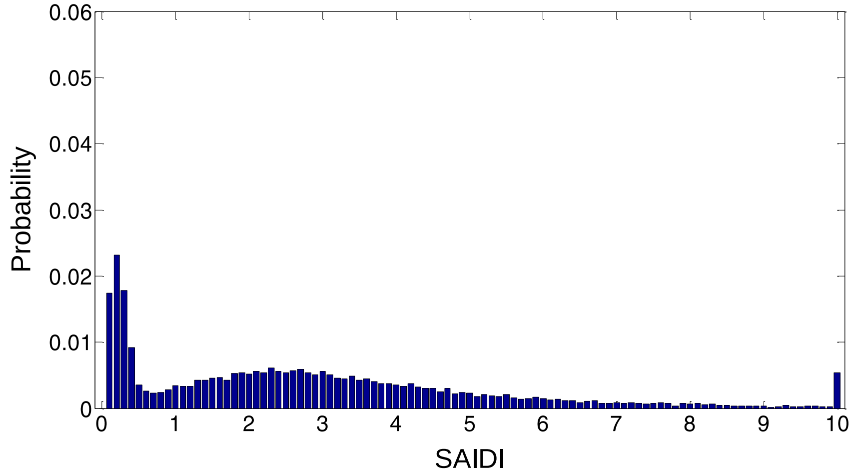

Fig. B.31 Distribution of SAIDI>0 when β = 2

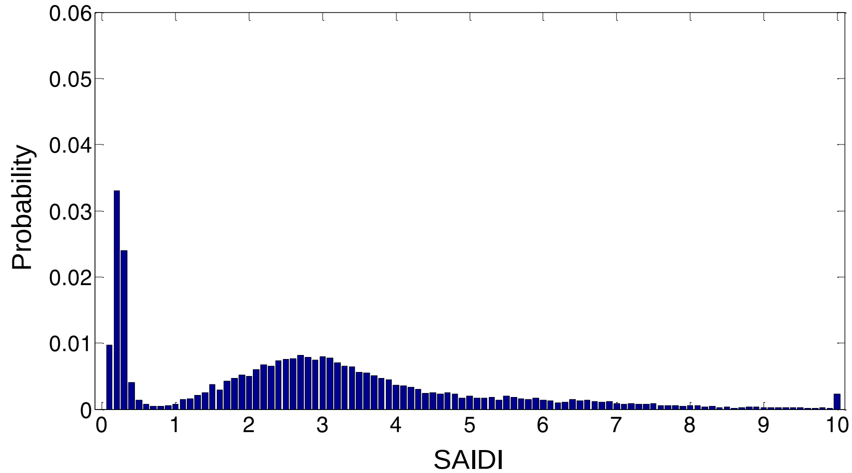

Fig. B.32 Distribution of SAIDI>0 when β = 3.5

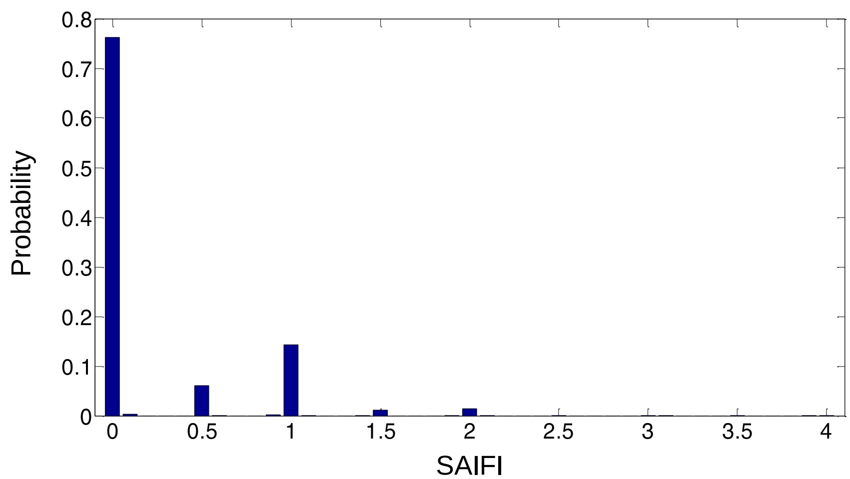

Fig. B.33 Distribution of SAIFI

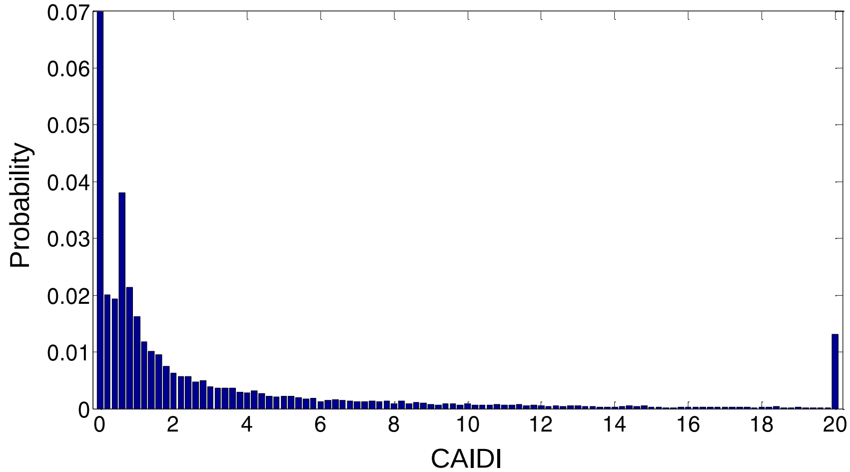


Fig. B.34 Distribution of CAIDI when β = 0.5

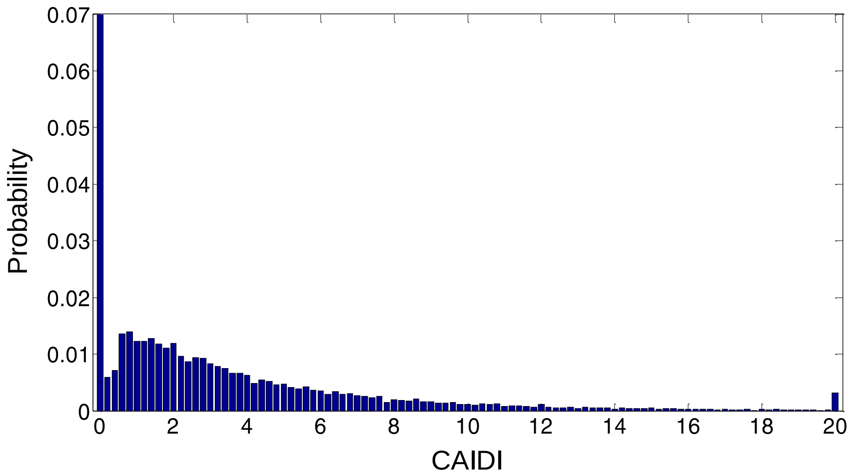


Fig. B.35 Distribution of CAIDI when β = 1

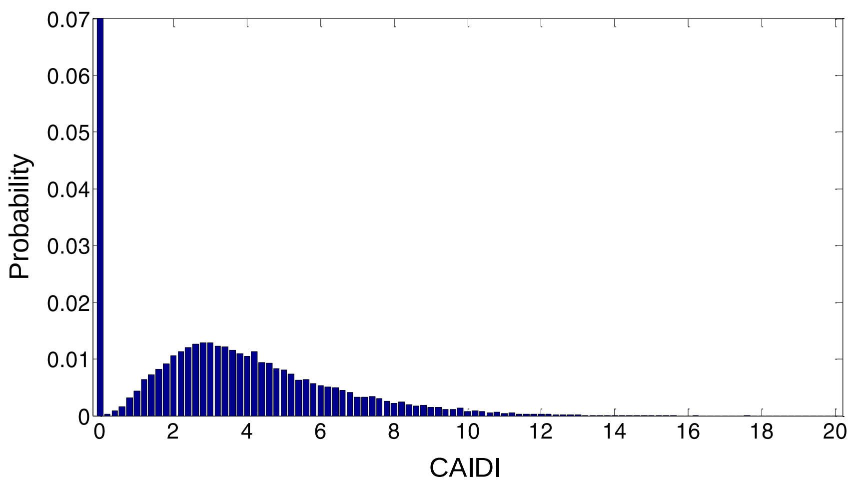


Fig. B.36 Distribution of CAIDI when β = 2

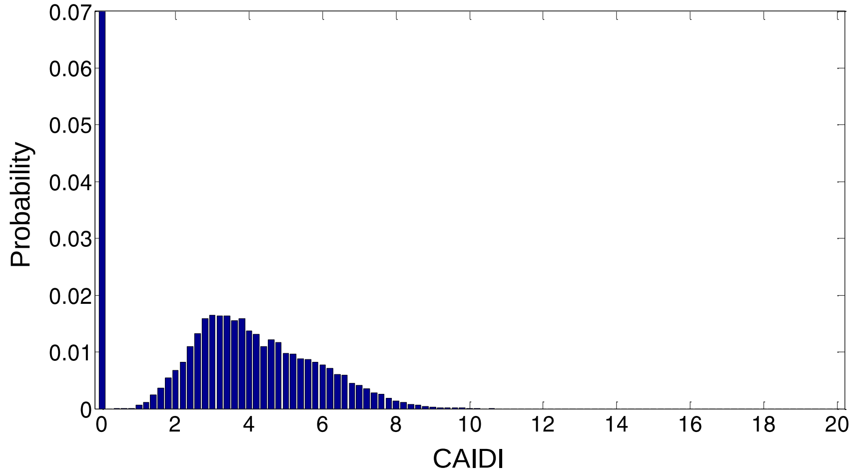

Fig. B.37 Distribution of CAIDI when β = 3.5

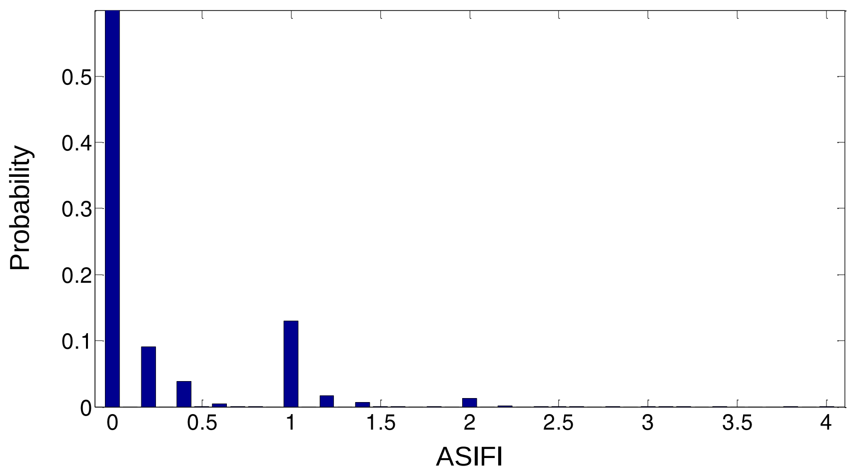

Fig. B.38 Distribution of ASIFI

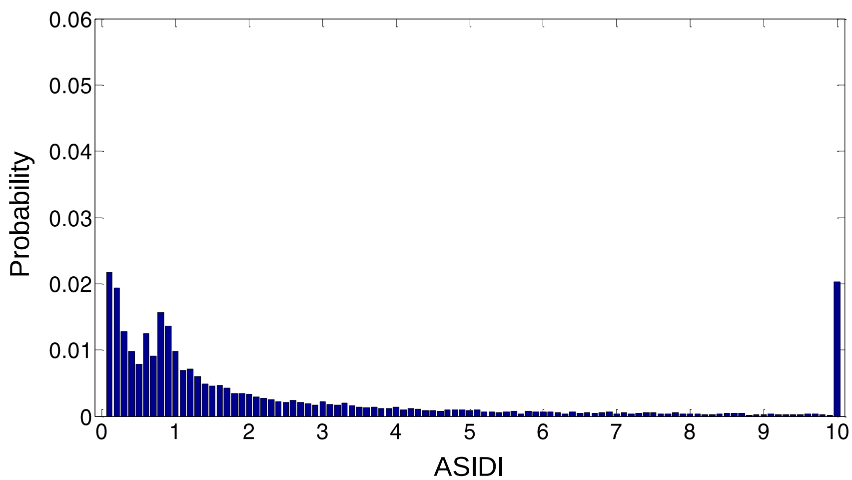

Fig. B.39 Distribution of ASIDI>0 when β = 0.5

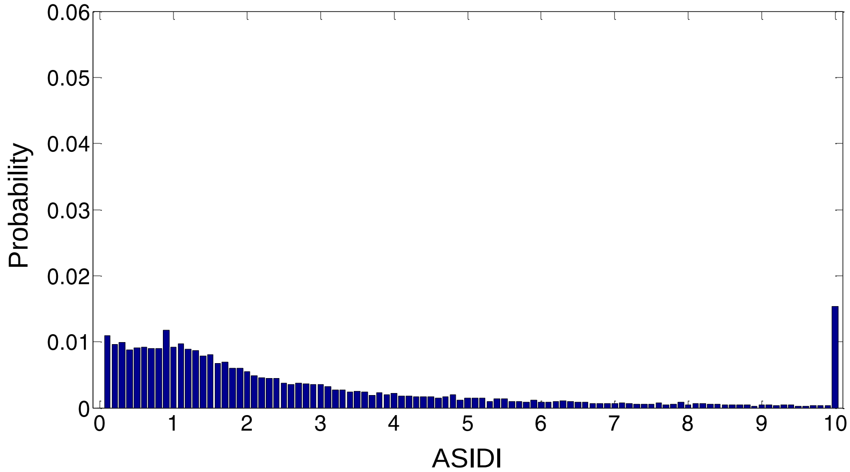

Fig. B.40 Distribution of ASIDI>0 when β = 1

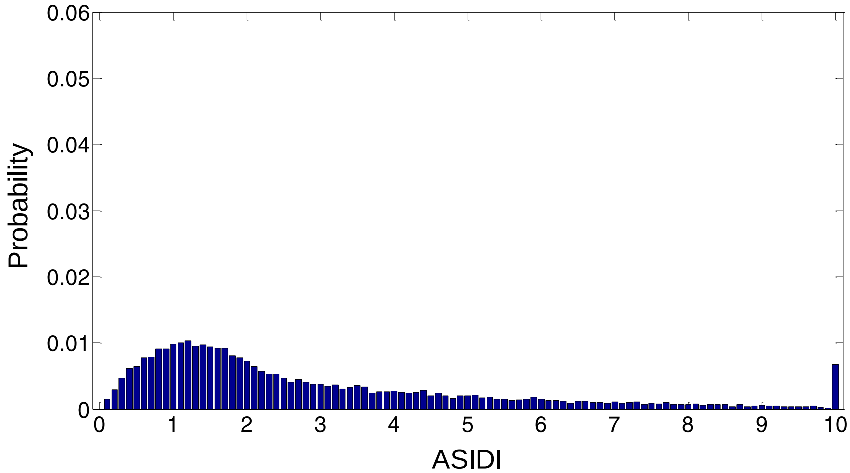

Fig. B.41 Distribution of ASIDI>0 when β = 2

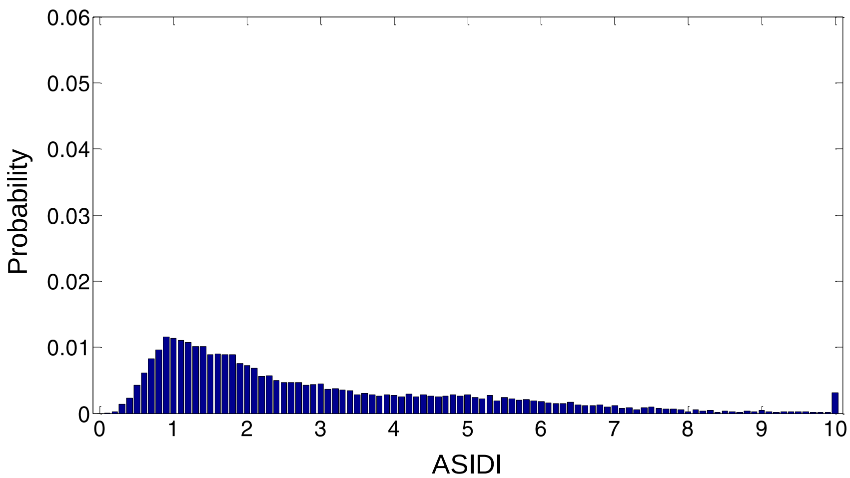

Fig. B.42 Distribution of ASIDI>0 when β = 3.5

### B.4 Probability Distributions of the System Indices of Feeder 4

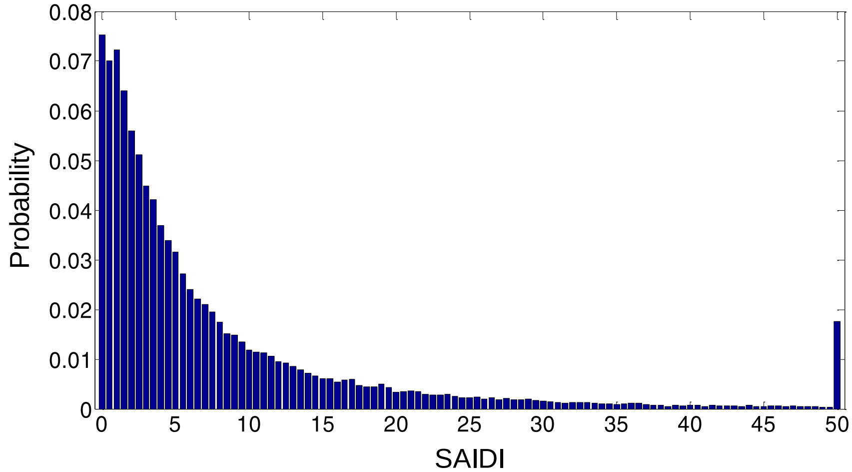

Fig. B.43 Distribution of SAIDI when β = 0.5

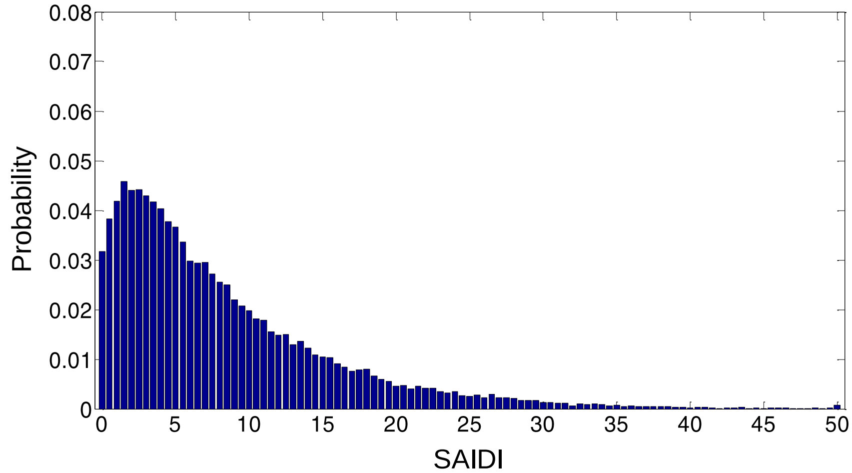

Fig. B.44 Distribution of SAIDI when β = 1

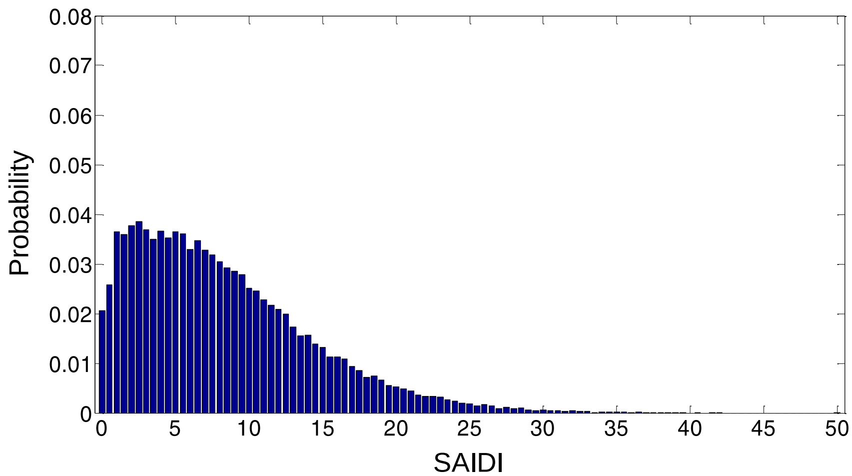

Fig. B.45 Distribution of SAIDI when β = 2

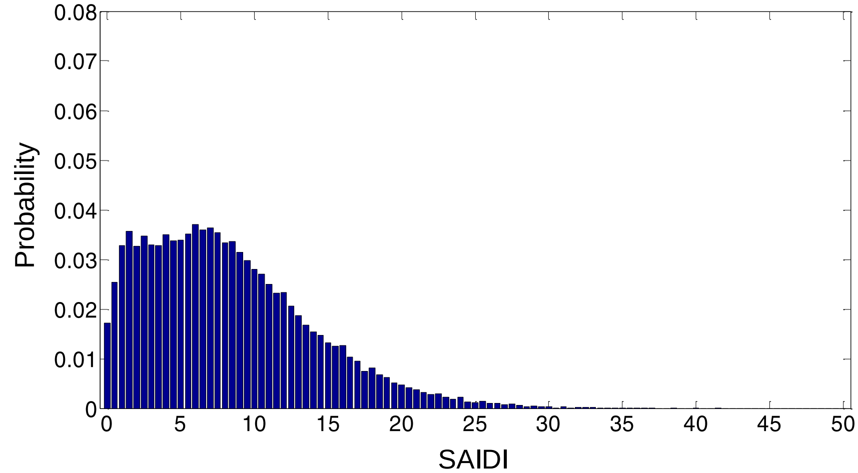


Fig. B.46 Distribution of SAIDI when β = 3.5

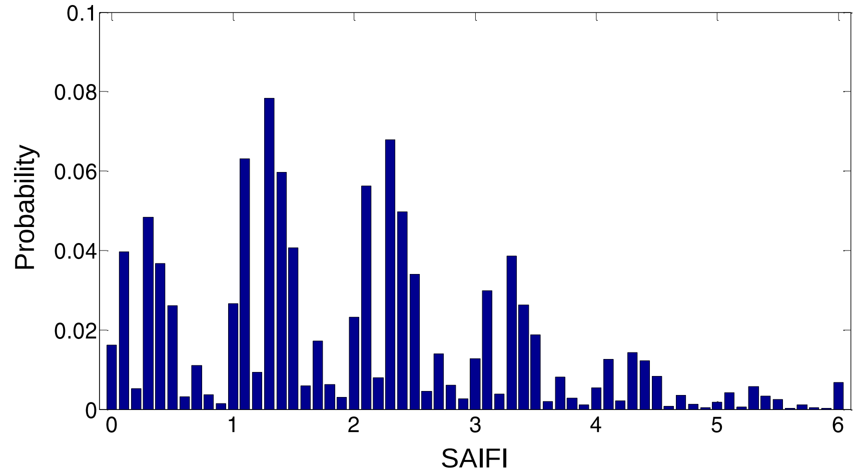


Fig. B.47 Distribution of SAIFI

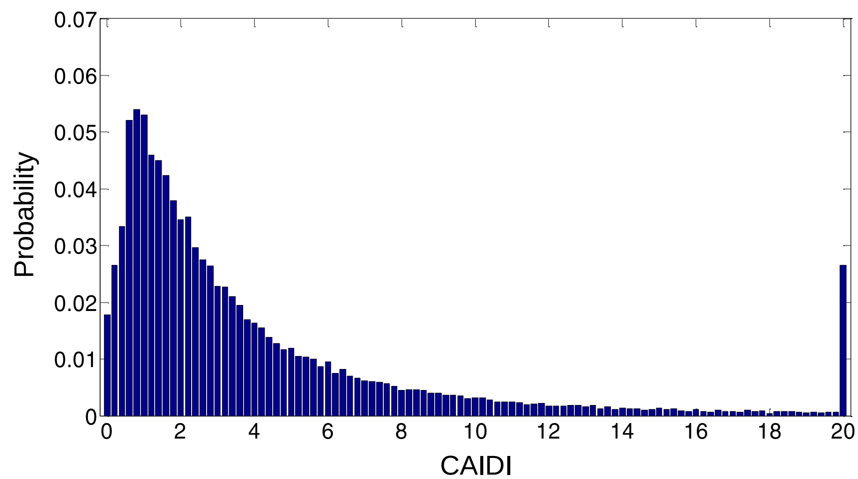


Fig. B.48 Distribution of CAIDI when β = 0.5

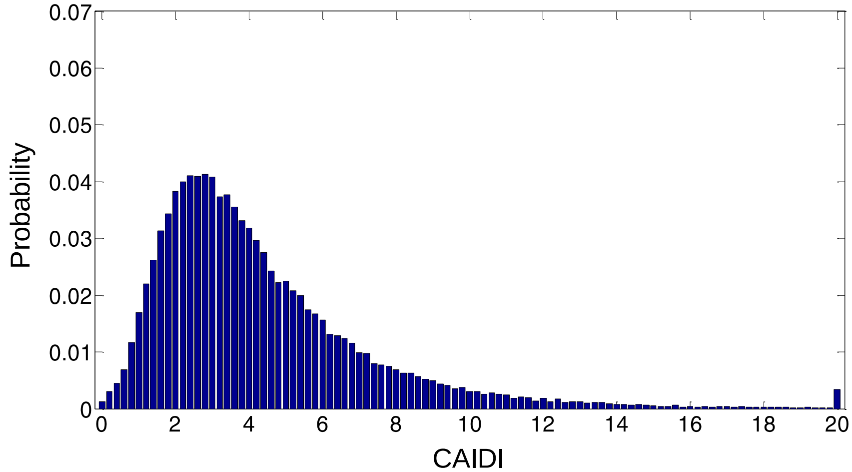

Fig. B.49 Distribution of CAIDI when β = 1

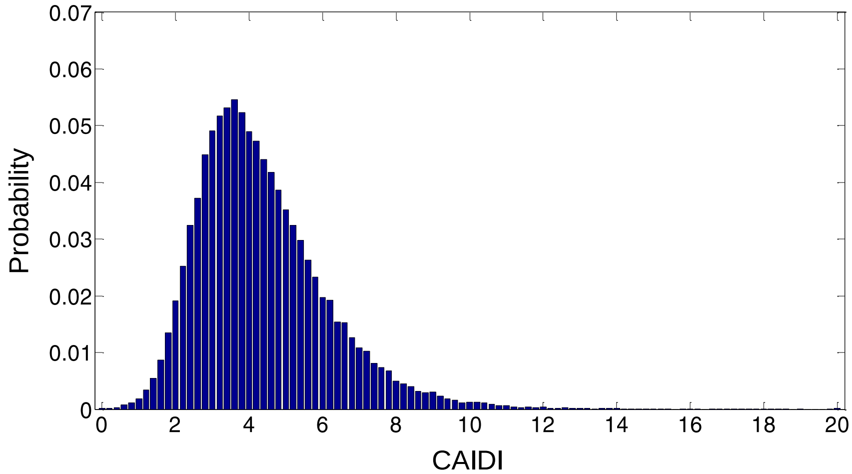

Fig. B.50 Distribution of CAIDI when β = 2

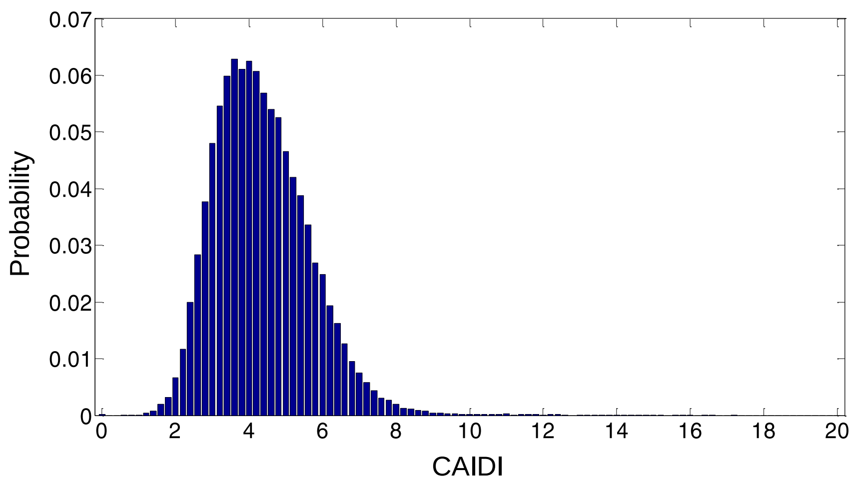

Fig. B.51 Distribution of CAIDI when β = 3.5

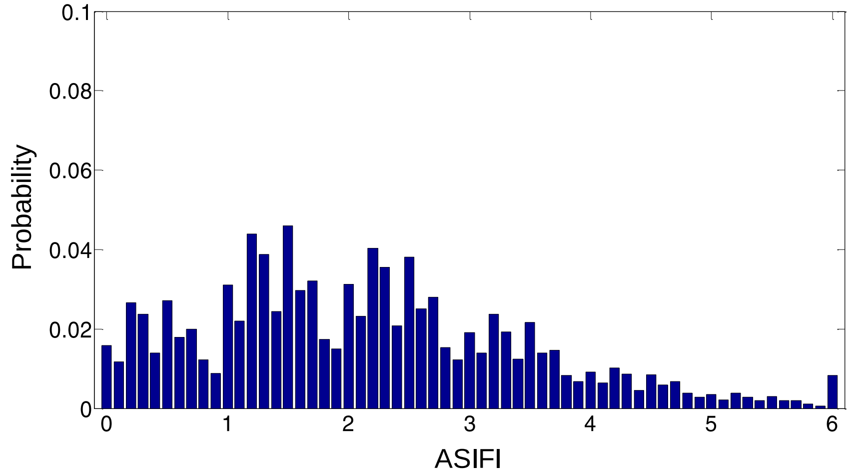


Fig. B.52 Distribution of ASIFI

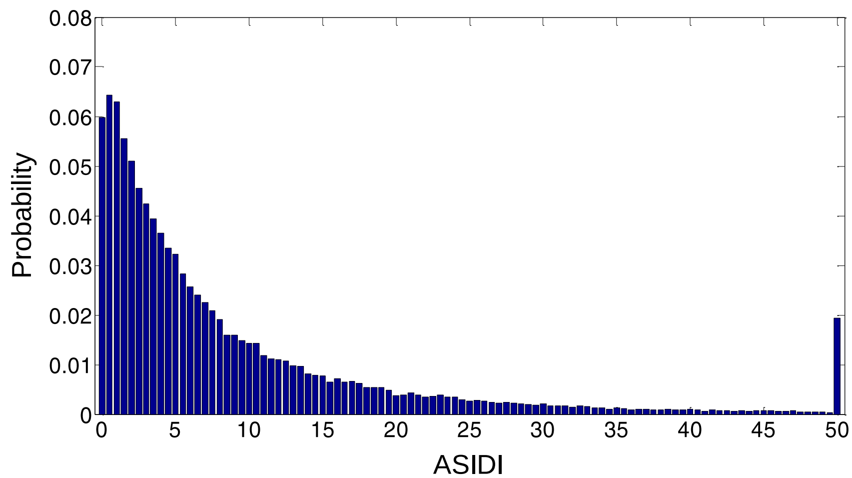


Fig. B.53 Distribution of ASIDI when β = 0.5

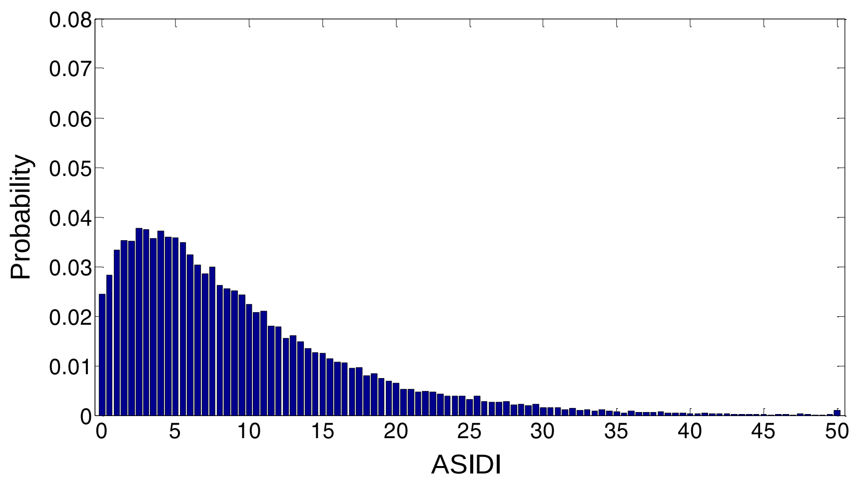


Fig. B.54 Distribution of ASIDI when β = 1

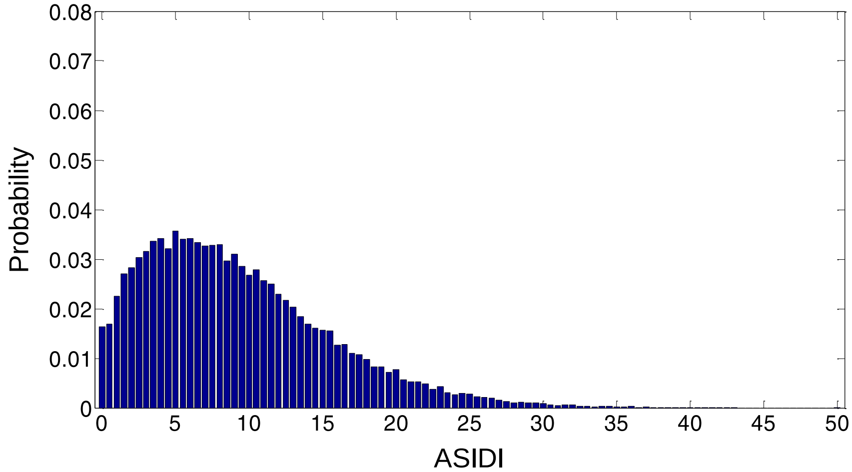


Fig. B.55 Distribution of ASIDI when β = 2

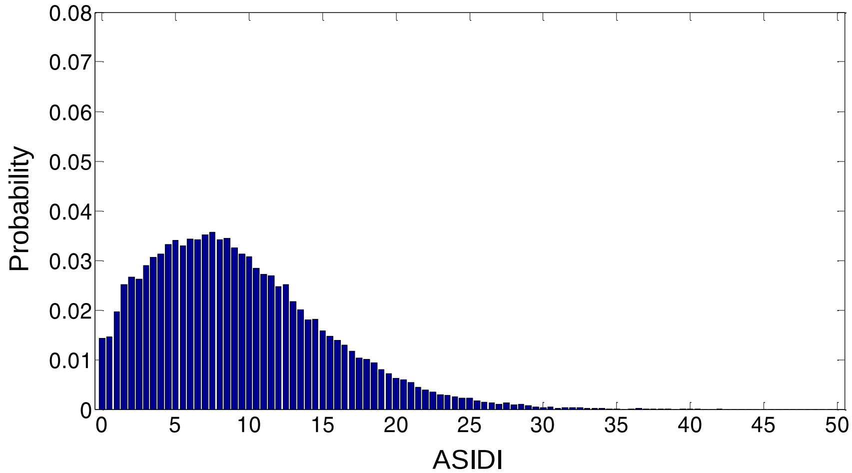


Fig. B.56 Distribution of ASIDI when β = 3.5

## B.5 Load Point Annual Outage Duration Distribution

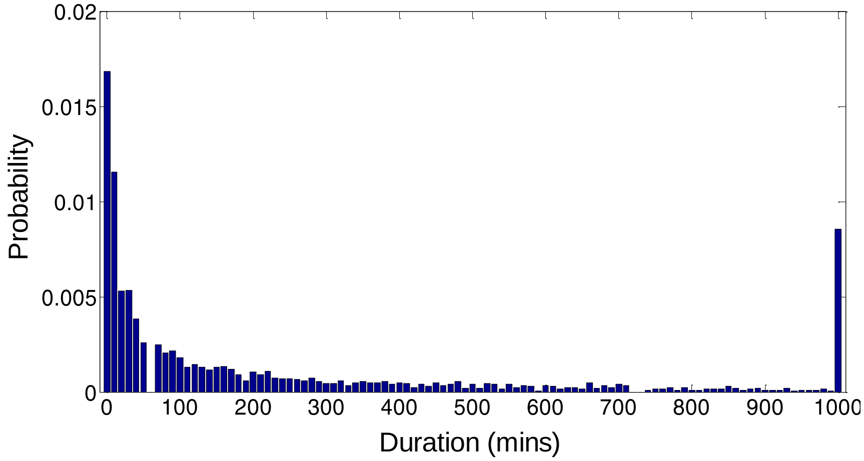


Fig. B.57 Annual outage duration distribution for Load Point 7 when β = 0.5

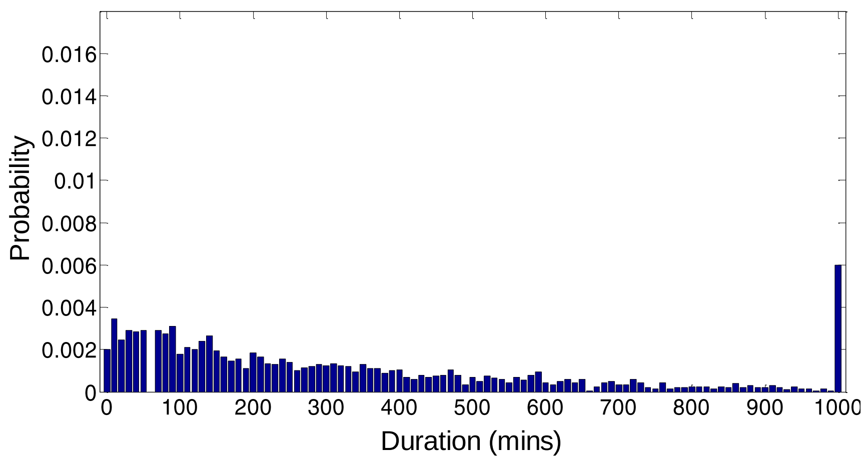


Fig. B.58 Annual outage duration distribution for Load Point 7 when β = 1

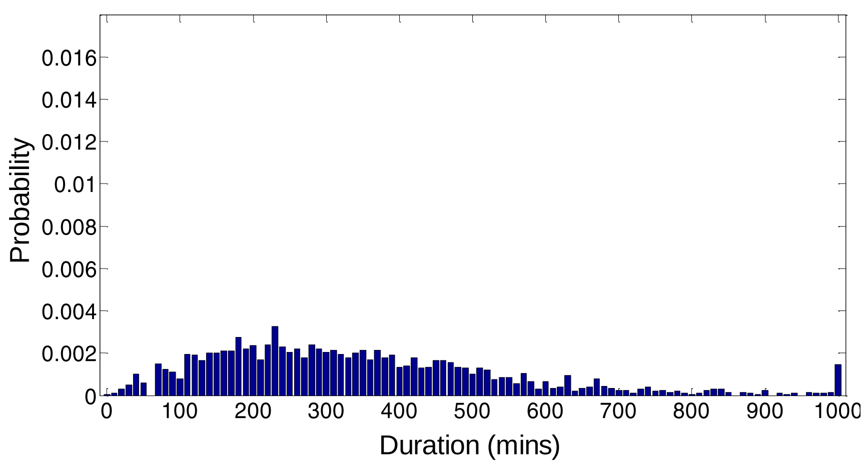


Fig. B.59 Annual outage duration distribution for Load Point 7 when β = 2

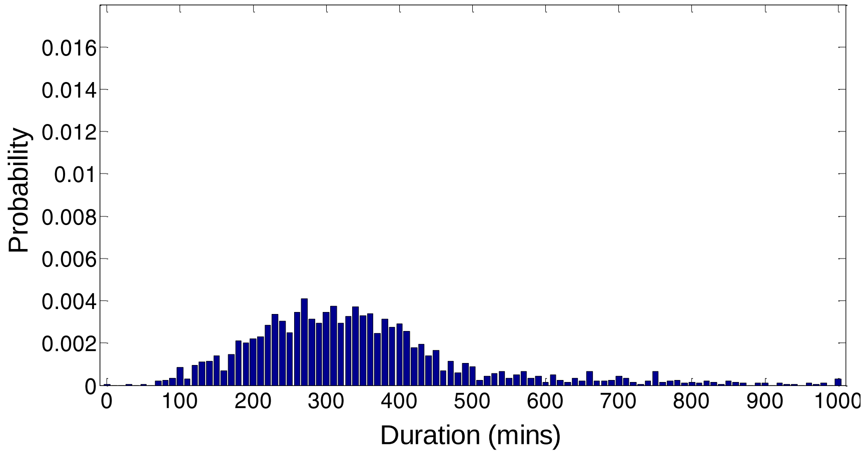

Fig. B.60 Annual outage duration distribution for Load Point 7 when $\beta = 3.5$

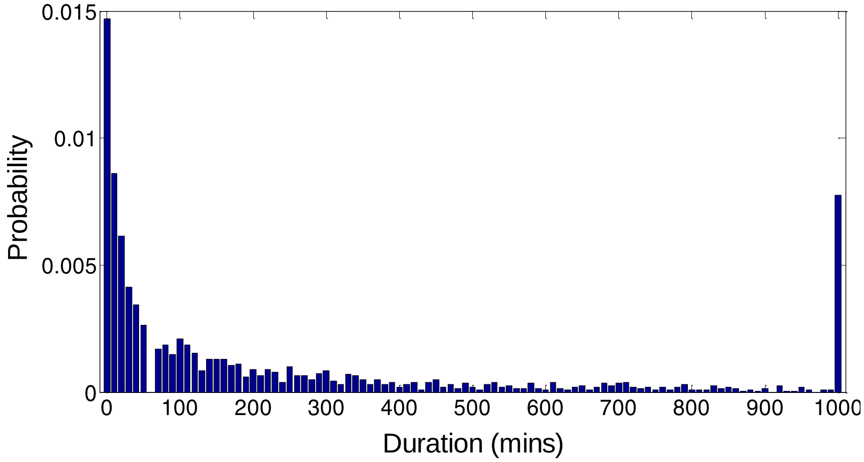

Fig. B.61 Annual outage duration distribution for Load Point 10 when $\beta = 0.5$

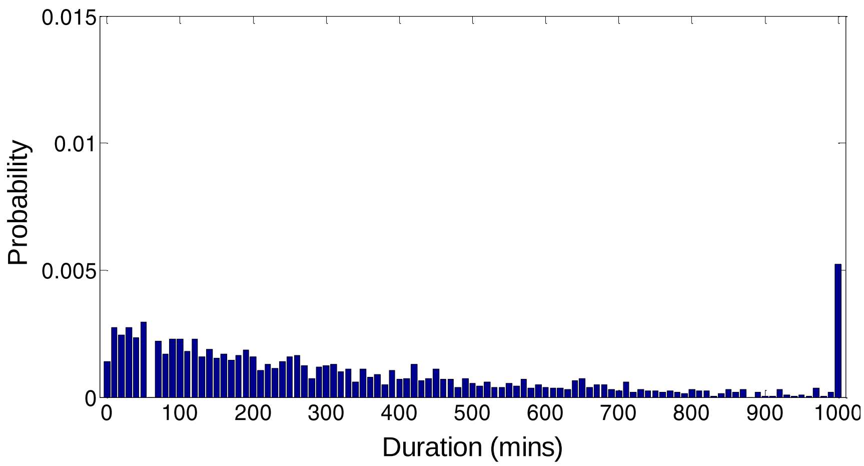

Fig. B.62 Annual outage duration distribution for Load Point 10 when $\beta = 1$

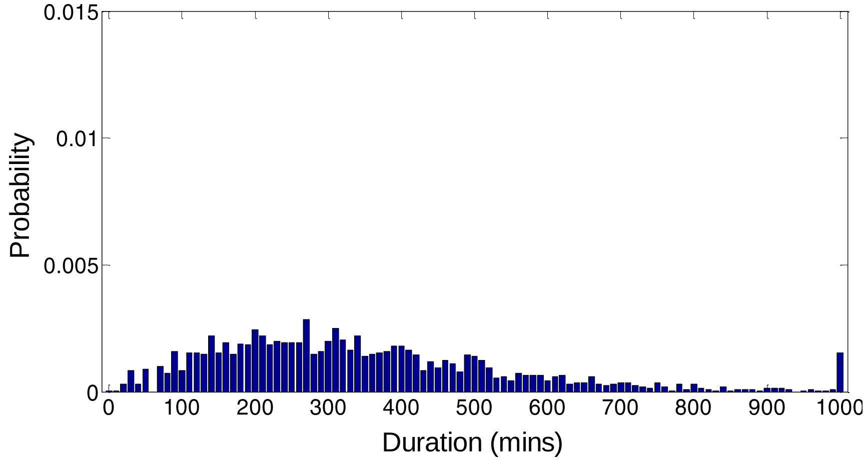

Fig. B.63 Annual outage duration distribution for Load Point 10 when β = 2

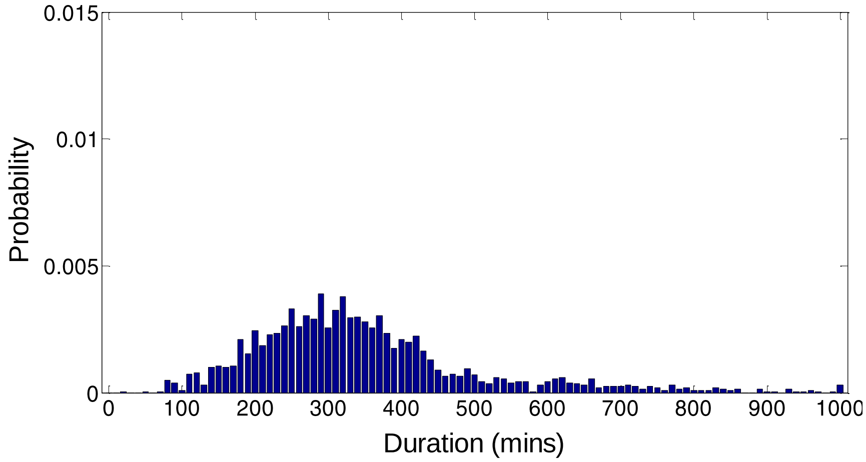

Fig. B.64 Annual outage duration distribution for Load Point 10 when β = 3.5

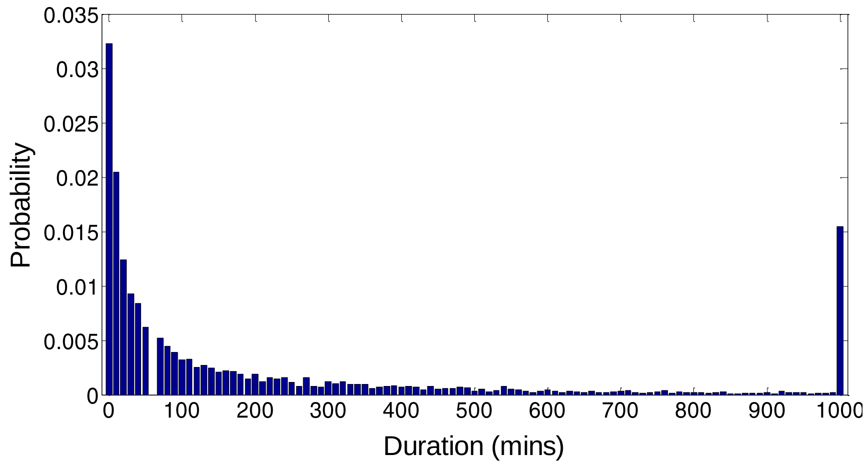

Fig. B.65 Annual outage duration distribution for Load Point 16 when β = 0.5

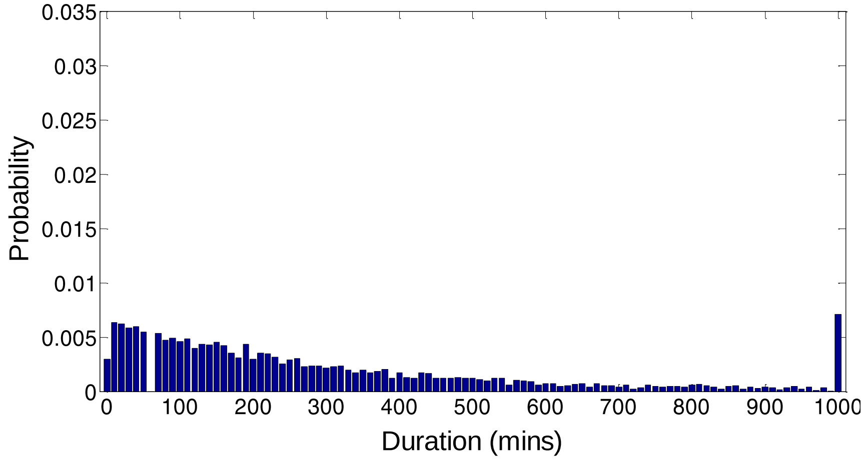

Fig. B.66 Annual outage duration distribution for Load Point 16 when β = 1

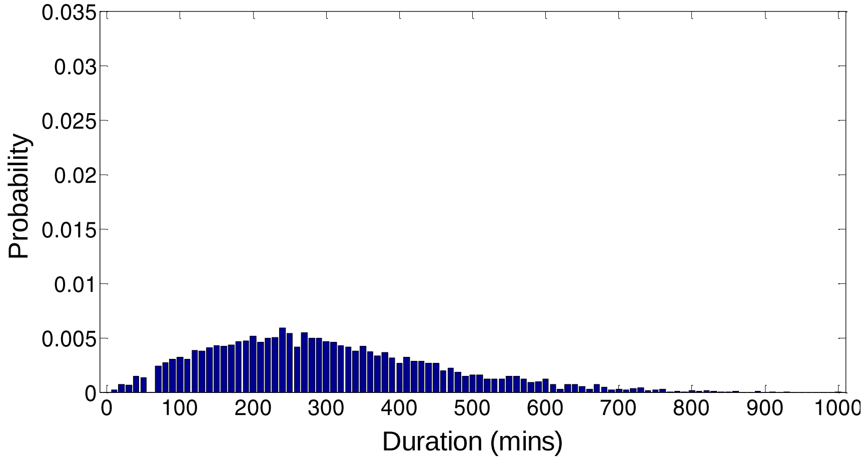

Fig. B.67 Annual outage duration distribution for Load Point 16 when β = 2

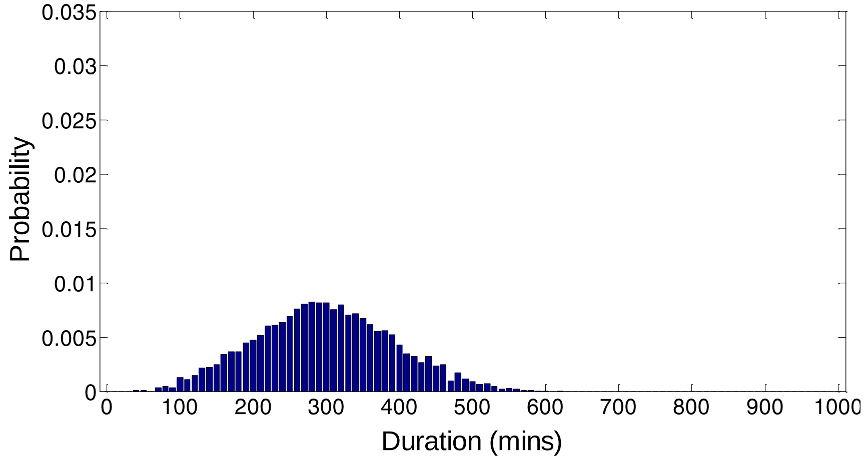

Fig. B.68 Annual outage duration distribution for Load Point 16 when β = 3.5

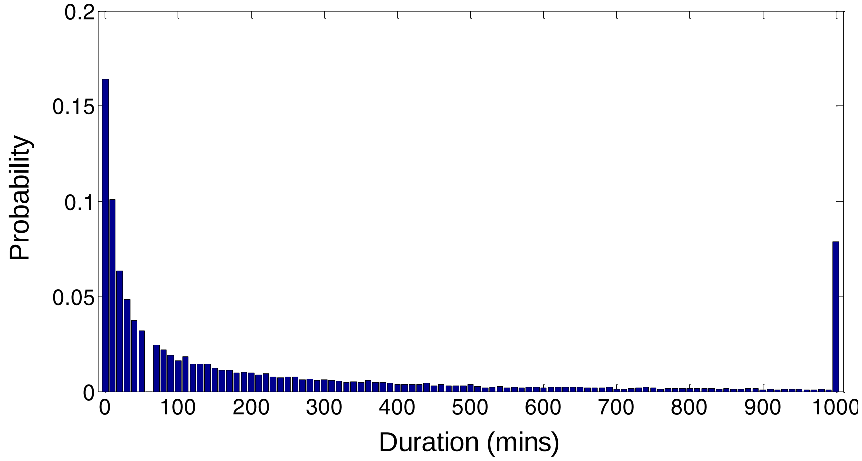


Fig. B.69 Annual outage duration distribution for Load Point 23 when β = 0.5

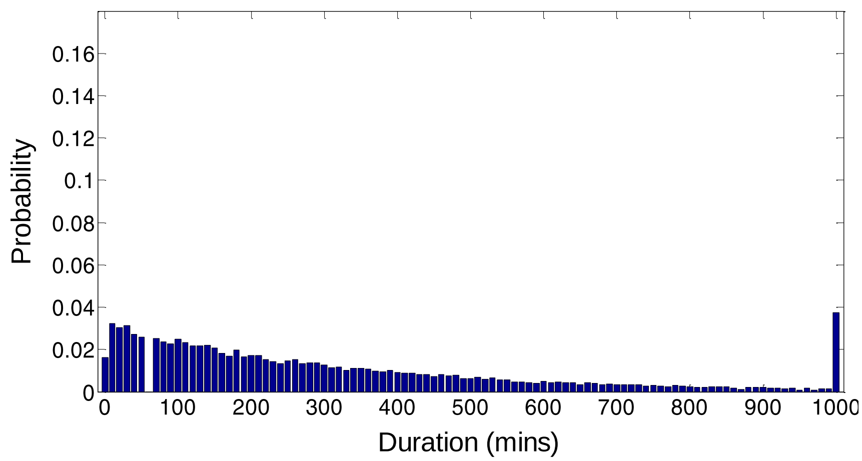


Fig. B.70 Annual outage duration distribution for Load Point 23 when β = 1

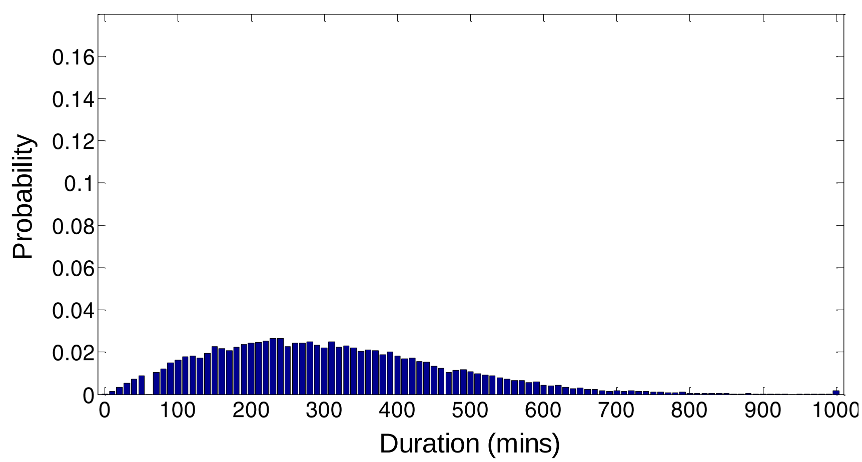


Fig. B.71 Annual outage duration distribution for Load Point 23 when β = 2

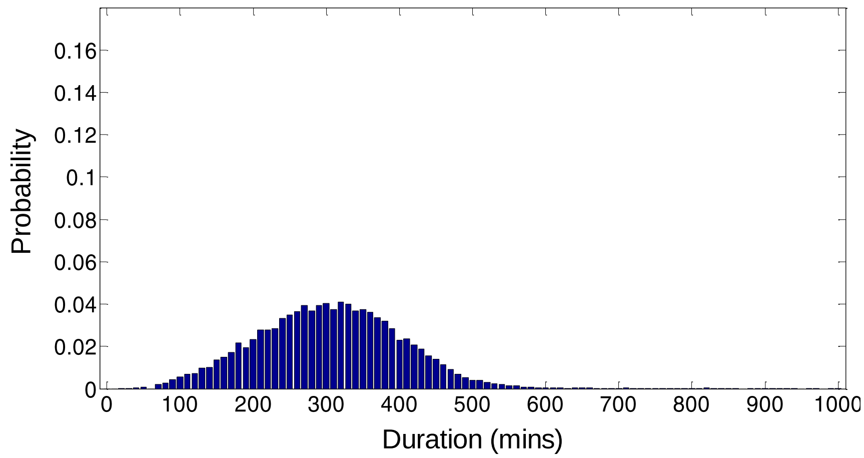

Fig. B.72 Annual outage duration distribution for Load Point 23 when β = 3.5

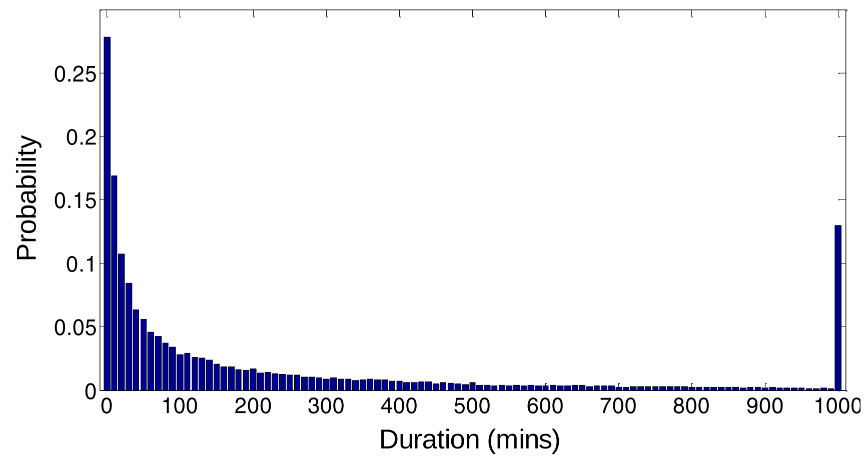

Fig. B.73 Annual outage duration distribution for Load Point 25 when β = 0.5

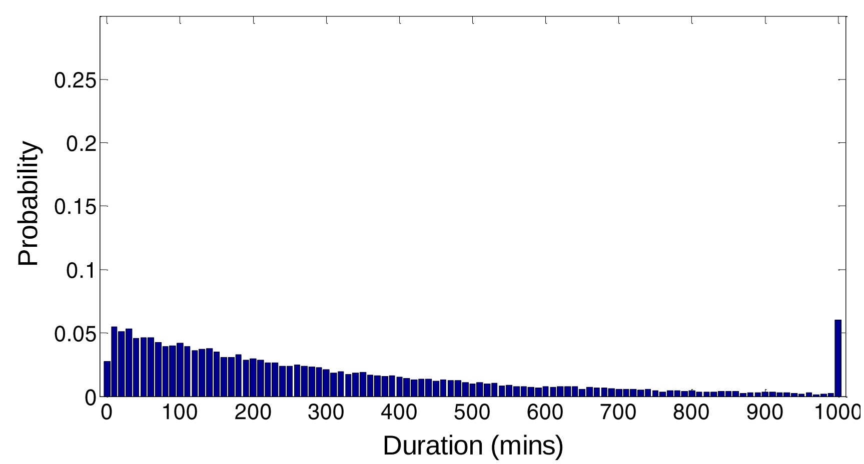

Fig. B.74 Annual outage duration distribution for Load Point 25 when β = 1

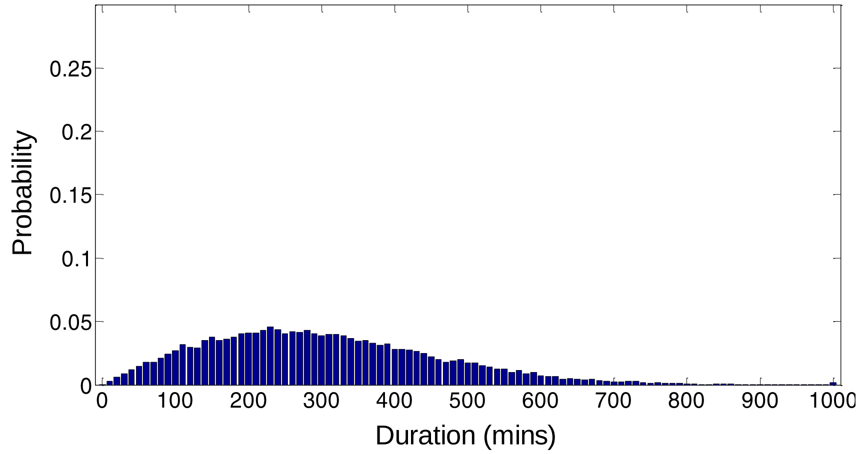

Fig. B.75 Annual outage duration distribution for Load Point 25 when β = 2

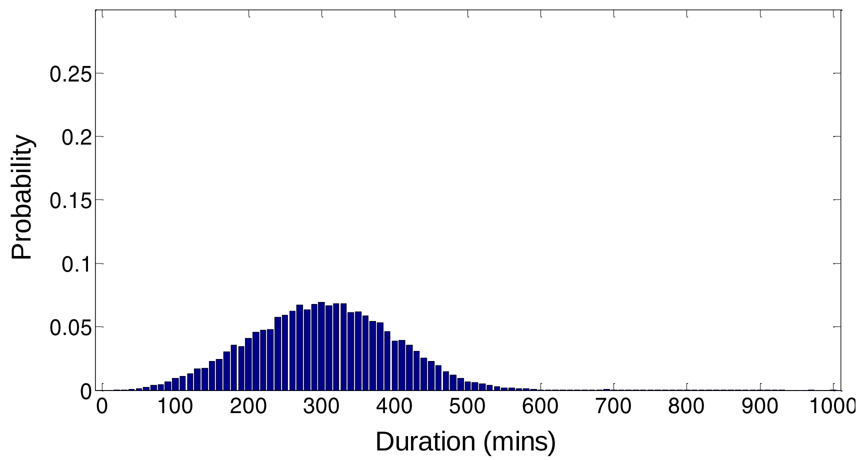

Fig. B.76 Annual outage duration distribution for Load Point 25 when β = 3.5

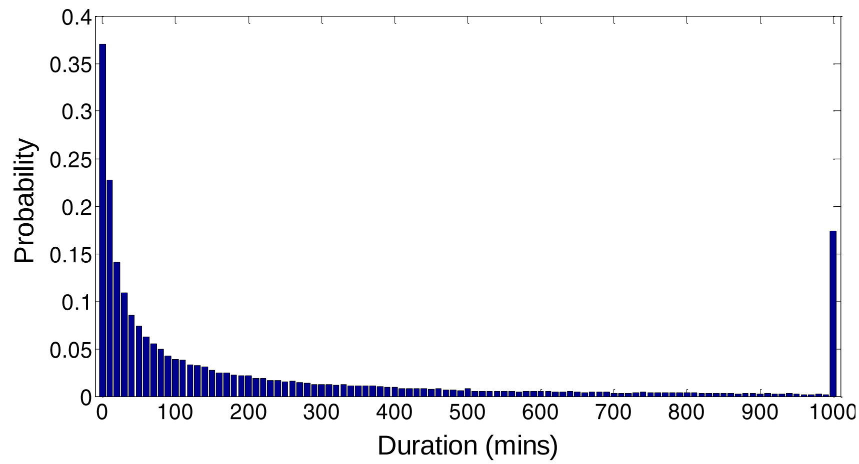

Fig. B.77 Annual outage duration distribution for Load Point 30 when β = 0.5

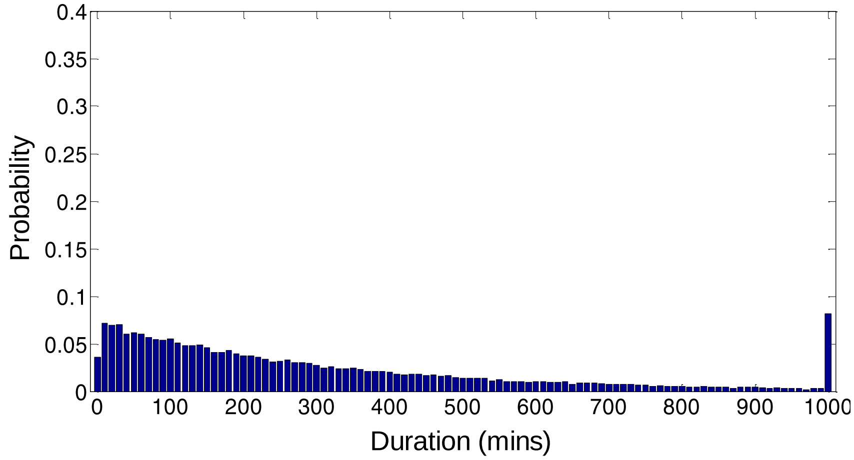


Fig. B.78 Annual outage duration distribution for Load Point 30 when β = 1

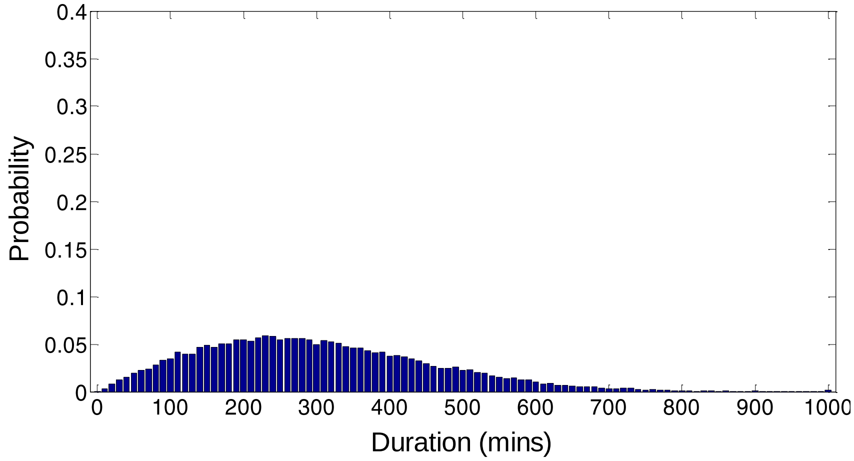


Fig. B.79 Annual outage duration distribution for Load Point 30 when β = 2

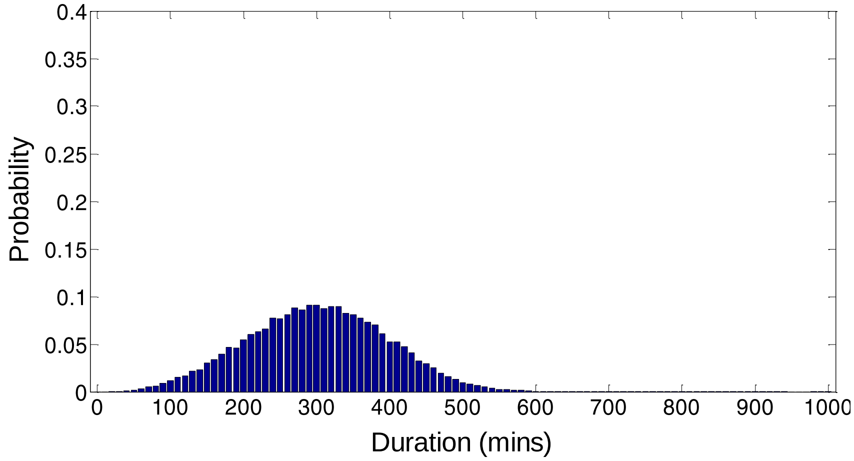


Fig. B.80 Annual outage duration distribution for Load Point 30 when β = 3.5

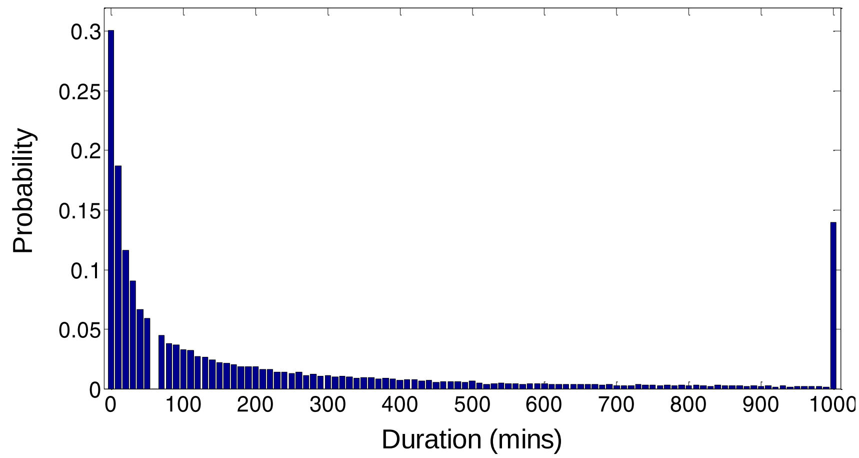

Fig. B.81 Annual outage duration distribution for Load Point 35 when β = 0.5

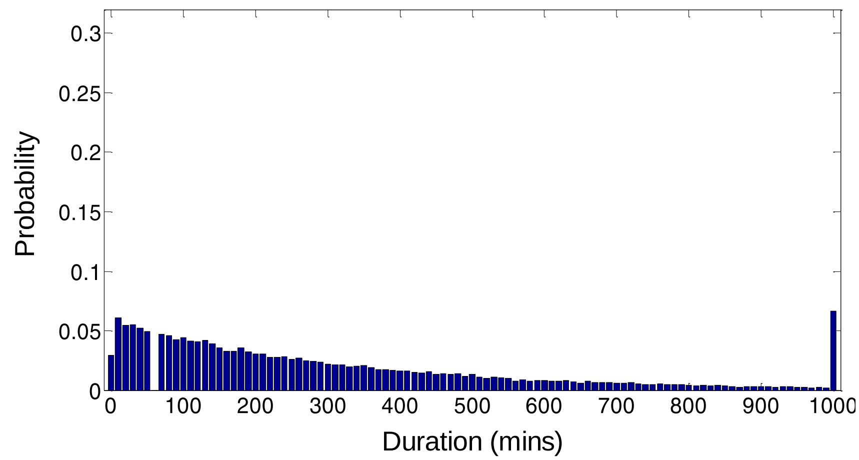

Fig. B.82 Annual outage duration distribution for Load Point 35 when β = 1

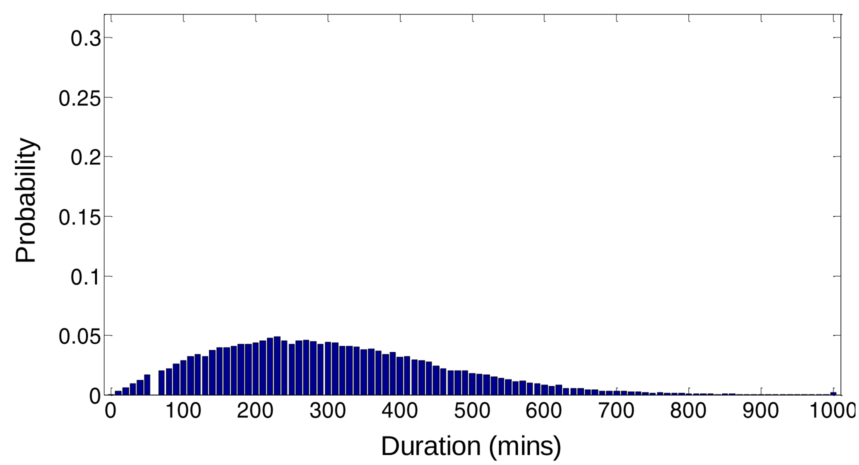

Fig. B.83 Annual outage duration distribution for Load Point 35 when β = 2

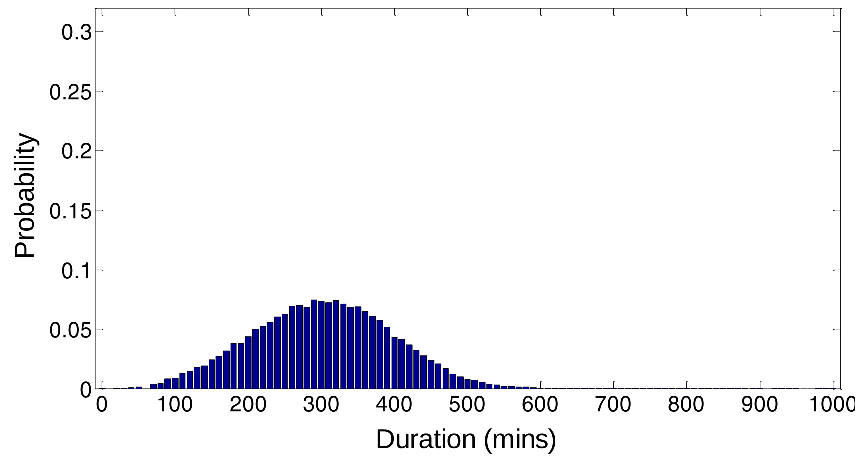

Fig. B.84 Annual outage duration distribution for Load Point 35 when β = 3.5

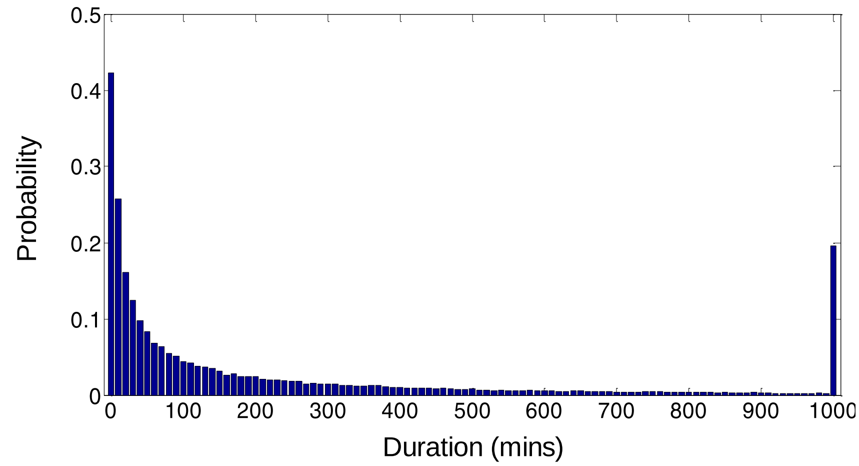

Fig. B.85 Annual outage duration distribution for Load Point 40 when β = 0.5

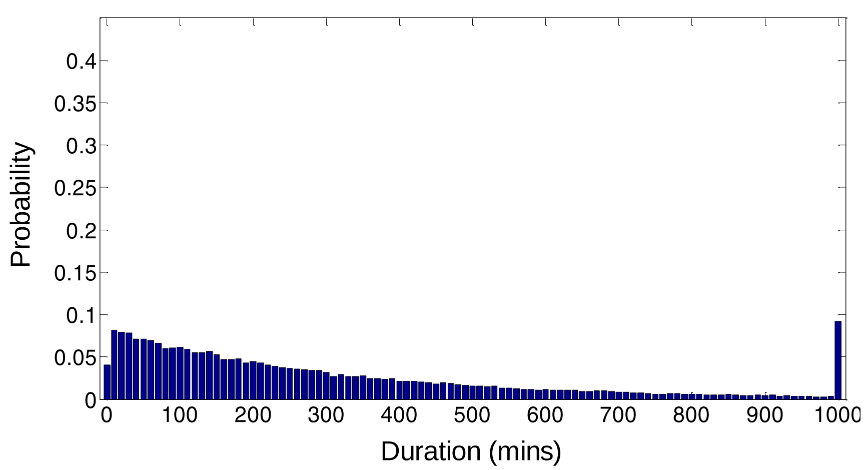

Fig. B.86 Annual outage duration distribution for Load Point 40 when β = 1

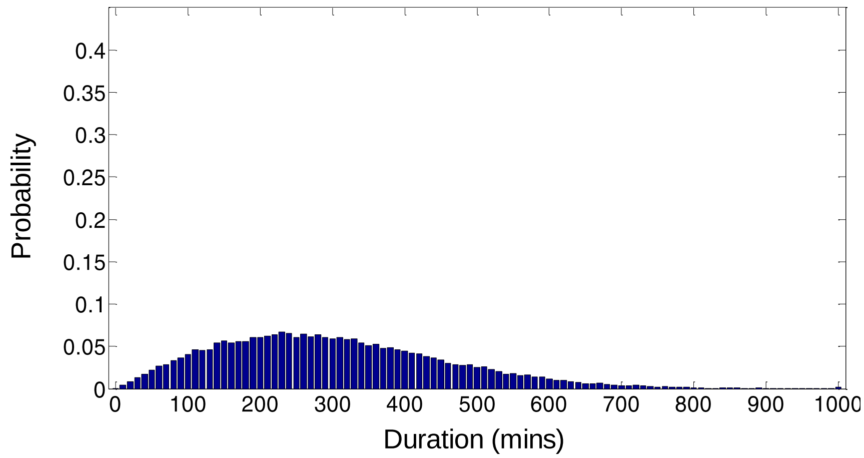

Fig. B.87 Annual outage duration distribution for Load Point 40 when β = 2

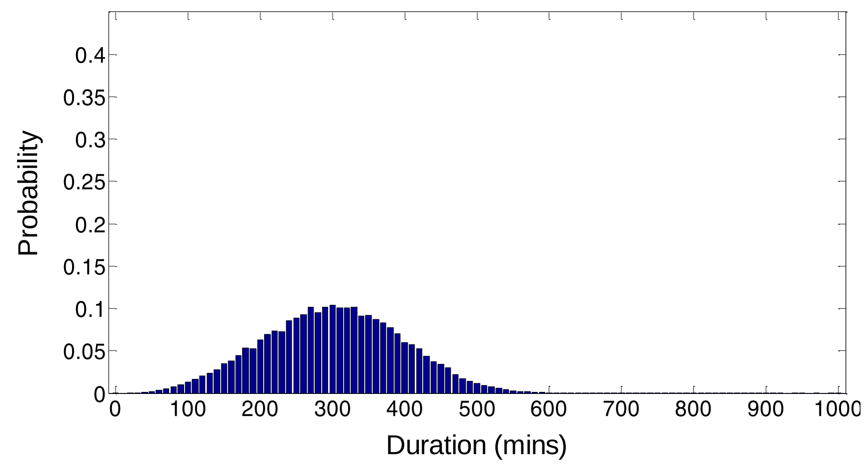

Fig. B.88 Annual outage duration distribution for Load Point 40 when β = 3.5